COMMITTEE HEARING

BEFORE THE

CALIFORNIA ENERGY RESOURCES CONSERVATION

AND DEVELOPMENT COMMISSION

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In the Matter of:                   )
                                    ) Docket No.
Preparation of the 2004 Integrated  )
Energy Policy Report (Energy Report)) 04-IEP-01-D
                                    )
Investor-Owned Utility Resource     )
Plan Summary Assessment Report      )
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CALIFORNIA ENERGY COMMISSION

HEARING ROOM A

1516 NINTH STREET

SACRAMENTO, CALIFORNIA

WEDNESDAY, JUNE 29, 2005

1:00 P.M.

Reported by:
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Contract No. 150-04-001

COMMISSIONERS PRESENT

John Geesman, Presiding Member

James Boyd, Associate Member

Jackalyne Pfannenstiel

ADVISORS PRESENT

Melissa Jones

Michael Smith

STAFF and CONTRACTORS PRESENT

Kevin Kennedy

Ross Miller

Karen Griffin

ALSO PRESENT

Harold LaFlash
Pacific Gas and Electric Company

Stuart Hemphill
Andrea Horwatt
Southern California Edison Company

Robert Anderson
San Diego Gas and Electric Company

Steven Kelly
Independent Energy Producers Association

Jack Piggott
Calpine Corporation (via teleconference)

Scott Cauchois
Office of Ratepayer Advocates
California Public Utilities Commission

Susan Freedman
San Diego Association of Governments

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P R O C E E D I N G S

1:00 p.m.

PRESIDING MEMBER GEESMAN: This is a workshop of the California Energy Commission's Integrated Energy Policy Report Committee. I'm John Geesman, the Presiding Member of the Committee. To my left, Commissioner Jim Boyd, the Associate Member of the Committee.

To his left, Mike Smith, his Staff Advisor. To Mr. Smith's left, Commissioner Jackalyne Pfannenstiel, a third member of the Commission. And to my right, Melissa Jones, my Staff Advisor.

Kevin.

MR. KENNEDY: Thank you, Commissioner. Good afternoon, everyone. My name is Kevin Kennedy and I am the Program Manager for the 2005 Integrated Energy Policy Report proceeding. I want to extend a welcome to everyone who is here in person, and also to the folks listening on the phone or on the webcast.

A quick reminder, as we're starting, to the folks on the phone. It is very helpful from our perspective if you keep your phone on mute unless it's time for a comment. Sounds from the phone lines do get broadcast into the room.

I just want to start by giving a quick overview of what we're going to be doing today. First, I'm going to give a quick walk-through of the resource plan information that the Energy Commission had asked for in terms of the forms and instructions, which will be the basis of what we are talking about today.

We will then give the opportunity for representatives of the three investor-owned utilities to provide brief presentations on their resource plan filings.

The main part of the day will be a staff presentation on the IOU resource plan summary report that was published on June 17th. And then opportunity for comment and discussion around that.

As I indicated, the Energy Commission directed the state's load-serving entities to file retail price, demand forecast and resource plan data for the 2005 Energy Report proceeding. Today's hearing will be very specifically focused on the resource plan information provided by the state's three largest investor-owned utilities, PG&E, SCE and SDG&E.

To provide some degree of context for what we're talking about today I just wanted to do a very quick walk-through of what the Energy Commission directed the utilities to provide to us in terms of the resource plans.

In terms of the basic format we asked for monthly capacity and energy resource accounting tables for the years 2006 through 2016. In those tables that provides opportunity to compare the expected demand with the existing and planned supplies to identify resource gaps. And also provided the utilities the opportunity to identify the general categories of resources that could be used to fill those gaps.

We do acknowledge that trying to look out to 2016 there are many uncertainties that affect the estimates of what the size of the gap may be, and how that might be filled. So there's a fair amount of uncertainty in terms of the resource plans that have been filed.

One of the things that we did in terms of dealing with that was to ask the utilities to provide a number of different cases and scenarios in terms of the monthly detailed information.

The one case that we asked all the

utilities to file was a reference case, where the Energy Commission defined fairly specifically the assumptions that we expected to see in the reference case.

For example, we directed the utilities to assume that the adopted energy efficiency and demand response goals are met; that the RPS goals that are currently set at 20 percent of retail sales being renewables by 2010 would be met; that there wouldn't be any additional migration of load to direct access, but we did ask them to assume some degree of departure of load to community choice aggregation or future municipalization.

In addition to that reference case, we also asked the utilities to file a number of other scenarios in terms of the detailed monthly information. To the extent that any of the reference cases for an individual utility included a major new transmission line, we asked that they include a separate scenario in which they assumed that the transmission line was not approved and did not go into effect.

For SCE that meant a case that did not include the Devers-Palo Verde II line. And for San Diego that meant a case that did not include a major 500 kV transmission upgrade into their system. PG&E did not actually assume a major transmission upgrade, so they do not need to provide a case of that sort.

We also directed them to provide a scenario that showed how they would meet the accelerated renewables goals that this Commission adopted as a recommendation as part of the 2004 Energy Report Update.

That recommendation would have the utilities achieving 33 percent renewables by 2020, in general, but also would have SCE in particular starting to add 1 percent a year immediately to achieve a goal of 35 percent by 2020.

Because our end year in the resource plans was 2016, what that meant was that PG&E and SDG&E would need to achieve 28 percent, on their way to the 33 percent goal, by 2016; and for SCE it would be 31 percent by 2016.

We also asked for a scenario that examined different assumptions on a core/noncore setup. And we also provided the IOUs the opportunity to give us their preferred case. If they felt that there was another set of assumptions that would better indicate what they expected the world to look like going forward, that they should give us a case in that direction.

All three did give us some additional case along these lines. Only one of them labeled it a preferred case. Two of them simply referred to it as an alternate case.

In addition to the detailed monthly information, there were a number of other -- much additional information that we did ask for in the forms and instructions, such as resource planning costs, assessments of local reliability, how the greenhouse gas adder would affect bid evaluations in the PUC procurement process. And a number of others. I won't go through the whole list there. It's listed in the presentation.

What we are primarily talking about today is the staff assessment of those IOU resource plans that were filed. The scope of the report that we're discussing is limited to the three IOUs. And much of the evaluation was an evaluation of looking at how the resource plans, as filed, matched up against the procurement mandates.

We also took a look at distributed generation; existing and planned resources such as the DWR contracts and QF contracts; took a qualitative look at the net open position. And also tried to look at the resource plan impacts and uncertainties and the transmission constraints.

This hearing today is just one of a series over the next month or so that we'll be looking at in a variety of ways at electricity and natural gas issues. Tomorrow we will actually have a second hearing that will be up at Cal-EPA; a hearing on the demand forecast, both the staff-generated demand forecast, and the demand forecasts filed by the various LSEs.

On Friday there is a workshop looking at the PIER research on strategic value analysis for integrating renewable resources into the state system.

Next week on July 7th there is a workshop on electricity issues and policy options. And yesterday we posted a series of questions that we are hoping to address at that workshop on our website.

On July 11th we have a workshop focused again up at Cal-EPA on energy efficiency issues and policy options. On July 14th we're going to be looking at the natural gas forecast and policy options.

On July 25th and the morning of July 26th we will be looking at both implementing the state's loading order for electricity resources and taking a look at the statewide WECC resource review.

On July 28th we'll be taking a look at the transmission system and policy recommendations there. And on August 9th we're planning to take a look at a number of scenarios within the natural gas forecast.

This is not a complete list of all of the IEPR-related workshops that will be held. There's also a number of others related to either transportation topics, and also a couple related to global climate change. So I would encourage folks to take a look at the website to get the complete list of all the topics that we will be dealing with.

Two that I did not actually include on this list that do relate to electricity will actually be in mid August. On August 15th and 16th we're going to be taking a look at a number of issues related to the role of nuclear power in the state. And on the August 17th and 18th we'll be taking a look at clean coal and what role, if any, that may have in the future of California's electricity system. So there's a lot more activity coming up.

One thing I would like to point out is that in terms of the staff report we will be discussing today there was a certain degree of limitation on how much of the detail of the monthly data we could get into, because the actual monthly detailed filings are being treated as confidential information.

Staff had put together, in early June, a proposal for how to provide both quarterly and annual aggregated versions of that information. We provided the IOUs and the ESPs several weeks to respond to that proposal. And actually it was today that we managed to publish a set of aggregate data tables that include, for planning area information, both annual capacity and energy information. And in terms of IOU customer-specific information, annual energy information.

The other portions of that aggregation proposal are being contested by the IOUs. And there will actually be a hearing before the full

Energy Commission on July 13th to consider that proposal to see whether or not the Commission believes that what was proposed by staff would be appropriate to be made public.

So, because we only published the aggregation tables today obviously we're not expecting anyone to have anything to say about them at this workshop. Most likely the place that they would come into play most directly would be at the workshops on July 25th and 26th. It may well be that they also provide useful information for any of a number of the other workshops that are on this list.

So, just wanted to make that clear, that in terms of what we're discussing today we're really going to be able to focus in on what we were able to say publicly in the June 17th IOU resource plan summary report.

I also want to remind folks, particularly on the webcast, that we do have a call-in number if you're listening on the webcast and find that you want to add some comments. The call-in number is up on the screen, 888-857-6266. The call leader is Al Alvarado, and the passcode is electricity.

And, again, we do ask if you are listening in on the call-in number please keep your phone muted, if you have that ability. If you don't, try to avoid background noise. It can be distracting at times.

And I would encourage use of the webcast if you have a choice of one or the other. Because with the webcast you also get to see the slides that are up on the screen.

So, with that, unless there are any comments or questions on that introduction, next on the agenda is actually for the various IOUs to have an opportunity to provide a quick overview of the resource plans that they provided to us.

And first on the list is PG&E.

MR. LaFLASH: Good afternoon, Commissioners. My name's Hal LaFlash. I'm Director of Integrated Resource Planning and Policy for PG&E.

PG&E would like to thank the IEPR Committee and the Commission Staff for all of its efforts in developing this staff report. We intend to make several brief comments and then take questions.

Our comments are first going to address

the general goals and observations of the process; followed by a discussion of preferred resource plan. And then it's relationship to the state's Energy Action Plan, which we believe is the appropriate focus for this process.

As there were no requests for cross-examination, we've not prepared a formal discussion of that process. But, of course, we'll take any questions you have.

Finally, we note that the Commission Staff report has some errors and clarifications required, and we will provide written comments on those. I will address those today only to the extent they come up in this afternoon's staff presentation.

PG&E supports the CEC/CPUC interagency collaboration on utility need assessment and resource procurement, and we look forward to the final report from the CEC IEPR Committee that satisfies the goals outlined in Commissioner Peevey's assigned commissioner ruling last fall.

PG&E would like to stress to the Committee that while this IEPR process is intended to result in firm recommendations, resource planning is an ongoing and dynamic process, especially in California. And we believe there are no right or wrong answers. And the Committee, in developing the resource recommendations for the CPUC, should resist the temptation to be overly prescriptive.

We provide this caution since the environment in which we operate is continuing to change rapidly and the resource plans need to be flexible to respond to those changing conditions.

If this sounds overly dramatic just consider that since we filed our last resource plan less than a year ago, we've had new energy efficiency targets, new demand response targets. We've made several filings to approve new supply side resources and demand side programs.

Going forward we can reasonably anticipate more changes, not the least of which are new resource adequacy requirements, implementation rules for community choice aggregation, possible new legislation, a ballot measure on direct access and utility service, and the continuing implementation of the California ISO's market redesign process. We believe our plans need to be able to adapt to these changes as they occur.

PG&E understands that the staff report addresses only the utility resource needs, that is the investor-owned utility resource needs. We would like to understand the process to identify the rest of the state needs, in that 30 percent of the energy in California comes from other than investor-owned utilities.

We've been working with the CEC Staff since the beginning of the year to insure the staff has sufficient and relevant information to implement the goals. And we've responded to numerous data requests, and are available to respond to more, if needed.

We're willing to furnish the Commission with all the information required, but we're reluctant to provide a number of -- a lot of this data without some confidentiality protection. PG&E believes that much of this data is commercially sensitive; it's not in the best interest of our customers to share this data with market participants. We're always willing to provide this Commission and nonmarket participants with the data necessary under the appropriate nondisclosure agreements.

Kevin Kennedy discussed the different

scenarios for the plans that were submitted. We'll emphasize our preferred plan. It was one of the four cases, as Kevin mentioned. The other three cases were designed by the CEC Staff and reflect the staff's views and assumptions.

We don't disavow the validity of any of their assumptions, but we don't necessarily endorse or embrace those as our assumptions. That's why we identified the one plan as our preferred resource plan.

We believe the preferred plan that we filed is consistent with the long-term plan that we filed last July, and was approved by the Public Utilities Commission in December. And it's also consistent with, in fact identical to, the plan that we filed on March 25th with the CPUC as an update to our long-term plan.

We believe that our preferred plan properly implements the Energy Action Plan loading order. We meet the energy efficiency targets and demand response programs for those targets.

Regarding renewables procurement we just recently filed four contracts from our 2004 solicitation, totaling 195 megawatts minimum, with the ability to expand those. We expect to issue a new RPS request for offer in August of this year. And we recently filed conventional generation, a application to complete the construction of the 530 megawatt Contra Costa 8 Unit earlier this month. And we're currently evaluating bids for shaping of peaking resources in response to a recent all-source RFO.

A summary of our resource planning assumptions discussion is available on the table in the lobbyway. And with that I'd be happy to either answer questions now, or if you'd prefer to wait for all three utilities, either way.

PRESIDING MEMBER GEESMAN: I've got a couple of questions. Could you describe for us how PG&E is going about applying the directive from the PUC's December procurement decision making renewables a rebuttable presumption for all procurement?

MR. LaFLASH: We have, through two processes, renewables are being solicited separately and through the all-source solicitation. The solicitation which we issued, I believe originally in November, and then reissued after we received the PUC decision in December, was an all-source solicitation that was available for renewables. And they would compete heads-up with other resources that were submitted through that process.

The thing to note is the rebuttable presumption, our resource solicitation specifically asked for peaking and shaping products. And we've yet to see a renewable proposal for a peaking and shaping product that was anywhere within shouting distance of a conventional resource.

PRESIDING MEMBER GEESMAN: Do you have an analytic framework that attempts to apply that rebuttable presumption approach? I certainly understand what you're saying as it relates to peaking and shaping resources, and I've anecdotallly been told that for a number of years. I'm wondering if you've got a specific methodology that attempts to apply a rebuttal presumption approach.

MR. LaFLASH: We do have a evaluation methodology that looks at several characteristics, including the market value of a particular product that we've asked for.

And as I said, we've only seen one renewable product that was submitted under that category. And there just isn't a competitive renewable product in that category now.

PRESIDING MEMBER GEESMAN: And is that market value assessment similar to the process the PUC uses in the RPS program for the market price referent?

MR. LaFLASH: It's more specific than that. In fact, the way we use the market price referent is specifically fine tuned to each utility. We have time-of-day factors that we use on the market price referent that gives higher weighting to peak hours.

PRESIDING MEMBER GEESMAN: I'm unclear. So, in your all-source solicitation do you take that utility-specific market price referent then to evaluate renewable bids?

MR. LaFLASH: The all-source solicitation, in that it was seeking peaking resources, didn't receive any bids from renewables for that category this time around.

PRESIDING MEMBER GEESMAN: Okay. Then maybe it was the shaping product that you were describing that did. I think you said --

MR. LaFLASH: No, actually the one -- I'm sorry, Commissioner -- the one we did receive was in a renewables-only solicitation that we evaluated separately, using the market value and time-of-day factors for that market price referent.

PRESIDING MEMBER GEESMAN: Okay. As it relates to the proposal you've made on the Contra Costa project, how has the rebuttable presumption analytic framework been applied there?

MR. LaFLASH: That was -- I don't have all the details of that filing, but that was basically, compared to the alternative for similar products and similar prices. And I can provide you with the application, but I don't have that detail memorized.

PRESIDING MEMBER GEESMAN: Yeah, I'm trying to determine the extent to which that proposal is consistent with the PUC's directive that renewables be a rebuttable presumption for all procurement.

MR. LaFLASH: I can respond to that in comments.

PRESIDING MEMBER GEESMAN: Okay. Other question is if you could elaborate upon how PG&E applies the least-cost/best-fit concept to its procurement. It's my impression that that lies at the root of all the PUC's procurement directives to the utilities. And I'm curious as to how your company chooses to define that.

MR. LaFLASH: Least-cost/best-fit is part of a -- there are several factors within least-cost/best-fit. Market value being one of those; transmission adders; CO2 adders. I think about half a dozen different factors. I don't have the formula in front of me, but it's basically a valuation that's applied to every resource that has to fit certain screening criteria and will come through with a point-weighting, basically that says this is how it comes through this model.

PRESIDING MEMBER GEESMAN: Could you provide us that in writing?

MR. LaFLASH: Okay.

PRESIDING MEMBER GEESMAN: Thank you very much. Other questions from up here?

Thanks a lot.

MR. KENNEDY: Next up would be Southern California Edison.

MR. HEMPHILL: Good afternoon, Commissioners. My name is Stuart Hemphill; I'm the Director of Resource Planning for Southern

California Edison.

Today I want to talk briefly -- first I want to summarize what we filed in support of the CEC's IEPR process. And I also want to talk and discuss some of the policy issues and omissions that are important to Edison, related to the CEC Staff's summary report.

First I'll describe our submittal. I think it's largely been described by Kevin earlier, but I will point out what we did file.

As requested, we submitted four scenarios. We had a CEC reference case with Devers-Palo Verde 2 transmission line. We also provided a reference case without the Palo Verde-Devers 2 transmission line. We provided an alternate scenario; and we provided an accelerated renewable scenario. We did not file a preferred resource plan as part of the IEPR process.

We also provided assessments and detailed discussions and assumptions on a variety of different topics. Generation cost estimates of our submitted scenarios. Local area reliability assessment.

We talked about how greenhouse gas adders would affect procurement choices. We gave information related to natural gas and wholesale electricity prices.

We discussed the impact of an early retirement of the San Onofre Nuclear Generating Station; and we also had a discussion of returning Mojave Generating Station to service as early as 2010.

And we also had a scenario evaluation of core/noncore departing load, assuming that 75 percent of customers with a peak demand of 500 kilowatts or more, would depart during 2009 to 2012.

We provided data and responses to every topic in the CEC's original request. And our total submittal was more than 3000 pages. And included more than 23 megabytes of supporting data and documentation.

We also have spent considerable time with the CEC Staff, and we appreciate the good working relationship we have with them. We've provided supplemental information and clarification regarding our submittal.

On June 17th we read the CEC Staff report that was published, and we appreciate the staff's effort in summarizing the IOUs filing in this report. However, the report does not properly represent SCE's position with regard to some important policy issues and contains some factual errors that must be corrected.

Since the report is slated to become part of the California Public Utilities Commission's 2006 long-term procurement proceeding, Edison believes it's important that the final version of the report correctly characterize the information provided, and fully reflect the concerns of Edison.

PRESIDING MEMBER GEESMAN: Let me make certain that we're on the same page in terms of semantics. What you're about to describe to us is your reaction to a staff report which is not going to become a part of the CPUC's procurement proceeding. A report from this Commission will end up becoming a part of the CPUC's procurement proceeding.

MR. HEMPHILL: Thank you for the clarification.

PRESIDING MEMBER GEESMAN: The staff report may or may not ever be finalized beyond the level that you're reviewing it today. So we welcome your comments, but I want to make certain that you understand that is a draft staff report. I shouldn't use the word draft; it is a staff report. And what you're ultimately likely to be most concerned with is what the full Commission transmits to the CPUC's procurement process.

MR. HEMPHILL: I appreciate the clarification. I'm new to this process, so I'm still learning.

The agenda today had us going first with the CEC Staff going second. And so this is a little bit of the cart before the horse. But I felt --

PRESIDING MEMBER GEESMAN: And that's okay. The agenda, also, is a staff product, so --

(Laughter.)

MR. HEMPHILL: Okay. So I thought I would comment on it and perhaps the staff can address these issues later on.

PRESIDING MEMBER GEESMAN: And we invite your comments.

MR. HEMPHILL: I appreciate that. Okay, the three areas that need to be addressed. The first is the CEC's recommendations on renewables. The second are the conclusions related to the Palo Verde-Devers 2 line. And the third are the energy efficiency and demand response goals in the CEC's reference case.

First, the CEC's renewable recommendations. As drafted, the report omits SCE's concerns about the CEC's recommendations to increase renewable portfolio standard beyond the 20 percent mandated level of retail sales.

The CEC has declined to perform any rigorous analysis of the feasibility of procurement targets above the 20 percent requirements. Relying instead principally on its assessment of the gross renewable resource potential. This assessment did not apply any economic filters to determine what resources can be expected to be developed, and at what installation and operating costs, including transmission costs.

Second, the CEC requested that SCE develop an accelerated renewable scenario assuming 31 percent level is reached by 2016, while other LSEs had a lower target of 28 percent. The CEC has yet to offer any rational basis for requiring greater renewable procurement targets for SCE, stating only that SCE is already the nation's leader in renewable procurement. Such reasoning for the imposition of an additional burden on SCE is illogical, unsubstantiated by any meaningful analysis and unsound.

California has gone to great lengths to insure that resource adequacy requirements are borne equally by all load-serving entities. The same policy should also apply with respect to all procurement obligations in order to assure that the burden of achieving desired policy objectives is distributed equally and equitably among all who are to receive the benefits of these policies.

Next I want to talk about Devers-Palo Verde 2. The report's transmission analysis misinterprets the information SCE provided regarding Devers-Palo Verde 2 despite SCE's attempts to insure clarity on the subject.

SCE's submittals in the IEPR process attempted to show that Devers-Palo Verde 2 needs to be evaluated on a Cal-ISO basis, as it is a project that will be utilized and paid for by all Cal-ISO jurisdictional load-serving entities to meet their respective customer needs.

The most comprehensive and useful information regarding D-PV2 can be obtained from either the CPCN application we filed at the

Commission, or the Cal-ISO's analysis, which is on their website.

The staff report looks only at SCE's increases in short term and spot market purchases, and reaches the erroneous conclusion that D-PV2 is being utilized only 13 percent. This conclusion is erroneous in two ways.

First, the values being used are short term and spot market purchases, not imports, as the report asserts. These purchases are from SP-15, from which the energy may originate within SP-15 or from anywhere outside SP-15.

Second, the D-PV2 project will provide access to greater generation for all load-serving entities within Cal-ISO, and not just SCE's customers. The actual usage factor of the D-PV2 project cannot be determined based on the data provided in the electricity supply forms.

Finally, I'd like to address the energy efficiency and demand response goals of the CEC's reference case. The CEC requested that SCE prepare a reference case assuming energy efficiency and demand response approved in the energy efficiency OIR and advanced metering OIR. However, no credible analysis has been provided by the joint staffs demonstrating that levels of energy efficiency and demand response beyond what SCE would determine as maximum reliable, achievable potential can be cost effectively and reliably achieved.

In its IEPR submittals SCE expressed concern that the required goals are not reliably achievable. And submitted an alternate resource plan with energy efficiency forecasts as based on our long-term procurement plan.

SCE's demand response forecast is based on SCE's 2005 program proposal reflecting revisions to SCE's demand response portfolio ordered in decision 05-01-056.

Accordingly, SCE reiterates that the basis for future recommendations should be the levels of energy efficiency and demand response identified as reliably achievable and economic. SCE's forecast meet these criteria, while the required goals do not. Edison encourages the CEC to reflect these policy issues and correct the specific errors identified today.

Thank you.

PRESIDING MEMBER GEESMAN: Thanks very much, Stuart. I do have the same questions that I asked PG&E. First, how do you go about applying the directive from the CPUC's December procurement decision that makes renewable procurement the rebuttable presumption or renewable technologies the rebuttable presumption in all procurement?

MR. HEMPHILL: Okay, let me first state that I'm the Director of Resource Planning, and we actually do procurement in the other department. But I can generally describe your answer.

We also do all-source bid solicitations where we encourage all generators to participate as we look for a very competitive offer. We include a greenhouse gas adder emission at the CPUC's directions And we believe that is the way to incorporate the rebuttable presumption the CPUC was requesting.

HEARING OFFICER FAY: So that the one component then that you would add to a nonrenewable bid or a fossil-based bid would be the CO2 adder?

MR. HEMPHILL: Well, we would look at the CO2 adders from all generating resources and to the extent renewable also had some element of greenhouse gas adders it would also be included there.

PRESIDING MEMBER GEESMAN: Okay. Any other adjustments?

MR. HEMPHILL: No.

PRESIDING MEMBER GEESMAN: And how do you go about applying the least-cost/best-fit criteria?

MR. HEMPHILL: WE look at our overall portfolio for meeting our bundled customers needs, and what we try to do is find products that will best meet the needs in the least cost manner. And we take into account the economics, take into account transmission, the greenhouse gas adders and the effects on the balance sheet in our evaluation.

PRESIDING MEMBER GEESMAN: That sounds like a policy. Is there a specific methodology that's utilized?

MR. HEMPHILL: We use a methodology that's consistent with that policy.

PRESIDING MEMBER GEESMAN: Could you provide us with a written explanation of that?

MR. HEMPHILL: Yes.

PRESIDING MEMBER GEESMAN: Great. Thank you very much.

MR. HEMPHILL: You're welcome.

PRESIDING MEMBER GEESMAN: Any other questions?

MR. KENNEDY: Next up is SDG&E.

MR. ANDERSON: Good afternoon; my name is Rob Anderson; I'm the Director of Resource Planning at San Diego Gas and Electric.

I'd first like to just note that SDG&E has reviewed the staff report. We do have a few clarifications and corrections that we would like to see included in the report should an update be provided. We'll be providing those in writing to the staff. None of them, though, are of a policy level that we feel necessary to bring them up with you today.

What I'd like to do is highlight a little bit about the cases SDG&E filed and the general assumptions that we made in each of the cases, and how they differed.

First of all, we filed four cases with the Commission. First was the reference case. This was heavily driven by the CEC's assumptions regarding energy efficiency, demand response, renewable power.

This case did include an assumption that SDG&E would have a new major interconnection in place by 2010. Although I would caution you at this point in time that when that case had to be submitted we were still in the process of studying 18 different possible interconnection requests. Therefore you should take what we have in this filing as being rather preliminary and not what may come out of any final interconnection studies.

We filed an accelerated renewable case. That case is identical to the reference case up through 2010. And then from 2011 on it just includes the staff's assumptions on additional renewable power.

We included a no-transmission case. My caution with that case would be the same as with the transmission case. Since we don't know exactly what the transmission line will do for us, it isn't right now a good assumption to make that that gives the exact difference in those two scenarios will be exactly what will occur without a transmission line.

Lastly, we filed an alternative case. And we filed this mainly because as we looked at a lot of the assumptions that were laid out in the other cases, it appeared to us that the vast majority of them had the implication of basically reducing the IOUs load. Because we took very high energy efficiency targets, very high demand response targets, and assumption that community aggregation would take some of our load away, and thus all of those drove down the utility's resource need.

And so we wanted to put one case in front of the Commission that showed that all of those may not come true, therefore our needs might be something higher than what those cases may have illustrated.

So, once again, not trying to say that that's necessarily what's preferred or that will be outcome, but once again to establish a range of need that the utility may have.

In developing these cases we started from new load forecasts. These load forecasts were based on the latest update and all the drivers, as well as reflecting quite the bounce-back that we've seen in demand over the last couple of years as we've come out of the energy crisis.

These cases were then reduced by the energy efficiency targets laid out by the PUC. I would like to note that SDG&E has expressed some reservation of those targets, although we continue to use them. As the report notes, the state has adopted targets statewide that are basically 90 percent of the maximum potential. However, the targets for SDG&E are actually at 118 percent of the identified potential.

We have some programs in the near term that we think we can achieve the near-term goals. We're just very cautious of believing that goal can be obtained in the long term.

In the area of demand response, the loads were reduced by 5 percent in all cases but the alternative case. In the alternative case we used a demand response scenario basically capturing the existing programs in the near term, and then ramping up as the AMI project goes into place more in the 2009, '10 and '11 timeframe.

With that we ended up below the 5 percent in the early years, and actually greater than the 5 percent in the later years.

In the area of distributed generation we updated our forecast there, heavily driven by the actual development of distributed generation that we're seeing in our service territory.

CCA assumptions, driven by the staff's

initial requests, although as I said, in the alternative case we assumed no CCA occurs in our service territory.

In the area of renewable power, in all cases we assume that the renewable power should be fully deliverable to SDG&E's load. And that somewhat drove our assumptions in this case. In order to make that happen we're going to have to add transmission, whether it be through the big interconnection project or other transmission projects in order to get that fully deliverable.

If you take that assumption away, basically the assumption that SDG&E could buy the renewable power, have it just delivered to SP-15, even though if it can't get in the SDG&E service territory, you could see a different pattern of renewable than what we have presented in the case.

And then finally we came down to the last of the resource needs. This could be met with supply side DG, power from existing contracts, repowers or new power plants. And we haven't made any judgment at this time as to what those sources would be.

With that, that concludes my remarks. Be happy to answer any questions.

PRESIDING MEMBER GEESMAN: Pose the same two questions that I did to both PG&E and Southern California Edison, and acknowledge up front I'd be happy and would hope to get a written response to both questions. But if you'd care to share anything with us verbally now, --

MR. ANDERSON: Sure.

PRESIDING MEMBER GEESMAN: -- that would be appreciated, as well.

MR. ANDERSON: Sure. We will provide a written response. In the area of rebuttable presumption, at this time, and as we stated at the PUC in our last resource plan, if you look at these resource plans you'll see that basically all San Diego is doing between now and 2010 is buying renewable power in order to hit that target.

So I actually don't anticipate that we'll be going out for any major RFP for anything but renewable power in the short term. And we don't have any RFPs out on that.

So this one may not be one that we will have to test as soon as the other two utilities do. But, we'll get you some comments on how we could implement that.

In the least-cost/best-fit test, when we implement that, what we really look at is what is the impact of the total portfolio given the resource addition. So it isn't is that one resource potentially cheaper than another resource, but how does it interact with everything else in the portfolio. And that's how we basically look at the least-cost/best-fit. And that looks at energy cost, ancillary service cost, transmission upgrades and anything else we can possibly model.

PRESIDING MEMBER GEESMAN: Thank you very much.

MR. KENNEDY: With that, unless there are any additional questions at this point, I will turn it over to Ross Miller from the electricity analysis office to walk through the key findings of the staff resource plan summary report.

MR. MILLER: Hello. I'm Ross Miller with the electricity analysis office. And I've got a fairly lengthy summary of our summary. And I will skip over a few of the slides. But if anyone has any questions about any of the slides, feel free to ask them even if I skip over them.

I understand the entire slide show is on the web, so people who are asking questions by phone, still feel free to answer them, and just please give me the slide page number to help me focus on the particular slide.

I'm not sure, some questions were addressed to staff by Edison. I could respond to some of them now, or I could respond to them while I'm going through the presentation. There's some danger I might forget about the questions when I get immersed in the presentation. But --

PRESIDING MEMBER GEESMAN: Why don't you go ahead and try and address them now, Ross.

MR. MILLER: Okay. On the issue of staff omitting certain statements that Edison made about the accelerated renewables policy in the 2004 IEPR update, the statements that Edison read sounded like statements I recognized from their filing. And staff concedes that those statements were omitted from our summary.

The question of did we misinterpret resources that the energy tables submitted by Edison were -- that were coming over Palo Verde-Devers 2 transmission lines in the case with that project, compared to the case without it, whether we misrepresented those as economy energy purchases or differently than what Edison says those resources are in their simulations, we don't have any dispute about that. That detailed information wasn't available, so we appreciate it as a clarification.

We did agree and note in our summary that Edison directs the Commission to the more comprehensive analysis of the cost effectiveness of the project that they submitted, which, as they described us taking account the whole region effects, rather than just the IOU portfolio effects that the forms and instructions requested.

PRESIDING MEMBER GEESMAN: So your analysis was confined to benefits only to the Edison service territory?

MR. MILLER: Well, our analysis was confined to just what Edison provided in its supply filings, and I think those were confined to that.

PRESIDING MEMBER GEESMAN: Okay.

MR. MILLER: That's why they suggested we not pay much attention to it --

PRESIDING MEMBER GEESMAN: Would a similar deficiency exist with respect to the San Diego transmission line, as well?

MR. MILLER: It's possible.

PRESIDING MEMBER GEESMAN: Well, did you evaluate benefits to the entire ISO control area?

MR. MILLER: No, we didn't. No.

PRESIDING MEMBER GEESMAN: Okay.

MR. MILLER: We just reviewed --

PRESIDING MEMBER GEESMAN: Would you agree --

MR. MILLER: -- the information provided in the filings by utilities. It's my understanding that staff is doing a more thorough analysis of transmission options in the staff report on that subject.

PRESIDING MEMBER GEESMAN: Okay.

MR. MILLER: On the issue of the energy efficiency and demand response goals, I'm not exactly sure if there is an issue with staff's characterization in the report. I believe we did note Edison's concerns, whether the goals that were used in the reference case were achievable or not. And pointed out that their alternate case does make a case for only assuming when calculating procurement residual need the more reliably predictable. So I believe that's in there. I may need a clarification of if there's a mischaracterization in the report. But I'm not sure how to proceed on that.

I think we have acknowledged the difference of opinion of whether the goals are achievable or not, as reflected in Edison's filing.

PRESIDING MEMBER GEESMAN: Okay. I do have a question before you start your presentation, would it be beneficial to invite the various parties that might have questions during your presentation to come up and sit at the table?

MR. MILLER: That's fine with me.

PRESIDING MEMBER GEESMAN: Okay.

MR. MILLER: I can answer questions as we go through the topics --

PRESIDING MEMBER GEESMAN: I'm thinking it's probably going to make it more accessible to everybody if they can ask questions as you go.

MR. MILLER: That's fine with me.

PRESIDING MEMBER GEESMAN: Why don't I ask then, anybody that does anticipate having questions or comments, and I certainly see the three utilities, I see ORA, I see TURN here. I don't know if there are any other parties, but I'd encourage you all to come up and sit at the table if you desire to.

On the other hand, saying no is not a problem, either.

(Laughter.)

MR. LaFLASH: PG&E has no questions.

PRESIDING MEMBER GEESMAN: Okay. Anybody have a desire to get in front of a microphone?

(Laughter.)

PRESIDING MEMBER GEESMAN: Okay, thanks very much. Ross.

MR. MILLER: I guess this is a good time to confess I really don't know a whole lot about these subjects. I'm just -- drew the short straw and I'm doing the presentation. But I do have --

(Laughter.)

PRESIDING MEMBER GEESMAN: We'll keep that in mind.

MR. MILLER: -- a variety of expert staff here, so when you ask a question of me that I can't answer, I'll point to one of them and they'll be sure to answer.

COMMISSIONER BOYD: Are you trying to draw them to the table?

MR. MILLER: Yeah, -- the one caveat is Sylvia Bender, who did the energy efficiency analysis, may not be here till later in the hearing.

One other thing I might point out is since the utilities were asked to provide a written description of how they implement the least-cost/best-fit criteria, and particularly how they take into account the December PUC decision on the rebuttable presumption of renewable resources, staff is also interested in the answers to those questions. And I think we attempted to provide what we thought was the answer to those questions in a report.

And so if I could direct the utilities to page 3, or basically to paraphrase, it's our understanding that regardless of least-cost/best-fit outcome, the utilities responsible for at least having the minimum percent of renewables in their portfolio that's specified by the Energy Action Plan, 20 percent by 2010, target.

And the PUC said also in the December decision that that's considered a floor, not a ceiling. So all solicitations should be open; all source solicitations where least-cost/best-fit criteria are used. And if renewables win on those criteria, including carbon adder, or at the time of the decision there was contemplation of the avoided cost proceeding might also have adders for criteria air pollutants and other environmental effects, that in those solicitations if renewables did best on the least-cost/best-fit criteria, then they would be the winning bids. And the fact that you'd already met your minimum was no excuse not to take the renewable power.

So, if the utilities, in responding to the Commissioners' questions, could include that, whether we've got that wrong or whether you think that's right, or any elaboration, staff would appreciate it, also.

We did also note that the specific detail of the implementation of least-cost/best-fit is basically confidential, and does differ by utility. And it appears in the public review groups of their procurement activities, and is commented on only in general within the procurement proceeding.

So, with that, I'll start going through my presentation. I was reminded to let the people in the web audience know that if you have questions you can call 888-857-6266.

The first few slides were already

included in Kevin's presentation, so I'm going to quickly flip through those. There was one on the supply forms format; the specified scenarios; additional forms and instructions, requirements. That's what the F&I stands for.

And this slide I'll spend a little bit of time on. It's a repeat of the organization of the staff assessment.

The focus of this assessment is really to review the myriad assumptions that are used to determine the IOUs' long-term generic capacity and energy procurement needs. That was basically the main point.

In the process we also identified some uncertainties in quantifying that. And identified some potential issues that we face in procurement.

I'm going to go back to that. The way we structured the report was to start first with the preferred resource procurement mandates including energy efficiency, price responses, demand or demand response, and RPS eligible renewable energy.

We went on to distributed generation, which is also preferred resource. There is no specific mandate for that resource as there are for the other three.

We talked then about this is basically the way we're grouping this together. And it does follow fairly much the forms and instructions outlined.

We talked about existing and planned resources and focused on two categories, the DWR resources and QF contracts. And when you add all those resources and compare it to demand, you get the net open position, or loosely, the need for further procurement.

We provided only a qualitative description. Kevin mentioned that just yesterday was published a summary aggregate of energy, annual energy versions of the energy tables for each of the investor-owned utilities for their bundled customer loads and resources. That wasn't agreed on at the time we published this report, so it was excluded. And our section here is necessarily short and descriptive.

The bulk of the forms and instructions, besides the resource plans, focused on having utilities provide either sensitivities or comments about the effects -- the impacts of differences between the plans or uncertainties that have to be taken into account when doing the planning.

And lastly, we talked about some of the transmission information that was requested in the forms and instructions.

This briefly goes over a description of the energy efficiency mandate. The goals were developed basically as an outgrowth of the 2003 IEPR by Energy Commission Staff. And subsequent to that -- those were statewide -- subsequent to that the PUC and CEC Staff got together and came up with individual goals for IOUs. And subsequently PUC directed that those goals be included in the procurement plans.

To characterize those goals, they basically are thought to achieve 90 percent of the maximum potential that can cost effectively be achieved through aggressive program activity. And that is, you know, 70 percent of what's actually considered to be cost effective potential. The difference is there's a realization that not all the savings can be achieved, even if cost effective by some measure, because there are some people that just will never adopt, or cannot be reached by these programs to implement these measures.

PRESIDING MEMBER GEESMAN: Do you have a response to San Diego's comment that in their service territory you've targeted them for 118 percent?

MR. MILLER: Be careful making generalizations. That's something -- Karen Griffin is going to help me with that.

MS. GRIFFIN: Thank you. The PUC has acknowledged that it has set that goal for San Diego Gas and Electric. And it said that in the post-2008 period in the next cycle they're going to have to revisit that goal based on new cost effectiveness information for San Diego.

So this report is just reflecting that's what the PUC has directed San Diego to work for in the long term.

PRESIDING MEMBER GEESMAN: I'm not clear. Does that mean that 118 percent is an acceptable and desirable target? Or does that mean that it's an error?

MS. GRIFFIN: I think people generally believe that if, in fact, it's 118 percent of the maximum achievable that's an error. And the question is whether the maximum achievable is correct or not.

PRESIDING MEMBER GEESMAN: Okay.

MS. GRIFFIN: And that there are new studies, cost effectiveness potential studies being done right now to try to test that information.

PRESIDING MEMBER GEESMAN: And are those likely to be available to us in this cycle?

MS. GRIFFIN: No, they will not be. The PUC is not proposing to revisit that goal until the planning cycle for the 2009 funding period. So that would be in 2008, I think.

PRESIDING MEMBER GEESMAN: Okay.

COMMISSIONER BOYD: I was about ready to ask is this issue therefore off the table.

PRESIDING MEMBER GEESMAN: Well, I think we've got to make some kind of adjustment. But, at least we know that it appears to be an erroneous number.

MR. MILLER: Well, this is where it would be nice to have Sylvia here, because in a minute I'm going to tell you that we are expecting these studies to be completed in August 2005.

PRESIDING MEMBER GEESMAN: Okay.

MR. MILLER: I guess it's a consensus of the PIER review groups, and this is a different group than the procurement review groups, and PUC consultants, that the short-term goals, meaning the goals for 2006 to 2008 should all be met.

One of the issues in comparing the filings was that each IOU's different method of reporting forecasted savings. Goals over this entire period, 2004 to 2013, were -- well, the goals are expressed through 2013, but the filings were required through 2016. So that was another difficulty comparing.

If the question is do they meet the goals, well we didn't have goals for the out years. So some interpretation is required there.

The comparisons were complicated and involved comparing both the demand forms and the supply forms. And Sylvia and the utilities' representatives spent quite a bit of time going back and forth and improving the original assessment.

And, in fact, we issued an errata that was a result of work she and Edison Staff did almost at the last minute of publication on their alternate case.

Both PG&E and San Diego's resource plans include a lag factor, meaning the savings show up not immediately when the funds are expended, but after that, which is expected. And --

PRESIDING MEMBER GEESMAN: Well, when you say it's expected, and San Diego and PG&E do it, does that mean that Edison doesn't?

MR. MILLER: I think by implication Edison does if they're including only what they consider is reasonably achievable, dependable capacity or firm energy savings. But that's a question for Edison to answer.

Is that a fair characterization?

MS. HORWATT: Could you restate the question, please?

MR. MILLER: I just reported that Edison -- or San Diego and PG&E use a lag factor. And so the question is since I didn't report that, Edison did, does Edison also use a lag factor?

MS. HORWATT: We don't use a lag factor in the savings, but --

COMMISSIONER BOYD: You're going to have to come up to a microphone, which is why Commissioner Geesman invited people, just in case.

PRESIDING MEMBER GEESMAN: You're also going to have to identify yourself.

MS. HORWATT: I'm sorry, I'm new at

this, too. My name is Andrea Horwatt; I'm from Southern California Edison. And I was part of Edison's Staff that worked with Sylvia on this.

To answer the direct question, we didn't have a lag factor, which basically means that in reporting the savings for a given year, what you're doing is not assuming that they'll be in place at the beginning of the year, but rather gradually over the course of the year.

We assumed that they would be in place, you know, for the entire year. And so we're reporting, you know, all the savings in a given year in that year. So it's not lagged.

In our reference case we do meet the goals as specified; however, in the alternate case, as is indicated here, we do not meet the goals with energy efficiency savings that we think are more reliably achievable.

PRESIDING MEMBER GEESMAN: Thank you.

MR. MILLER: As far as the issue of how does this affect the procurement, the estimation of what is a residual need that needs to be procured, it becomes important when you do an annual summary of these tables.

The information they filed is monthly.

So if you're having increasing savings over the course of the year, you'd want to be careful to look at what was available at the beginning of the summer when you selected your annual value. Because if it's available in December of that year, that amount is not available necessarily during the summer.

And I think when we did the aggregate summary tables, we took that into account.

PRESIDING MEMBER GEESMAN: Steven.

MR. KELLY: One quick question. This is going back a little bit, but when I look at the scenarios that you've run, which are the reference case assumptions, accelerated renewables, core/noncore and preferred case in the IOUs, and when I look in terms of this energy efficiency I see you've got an analysis of the IOU assumptions, or what they incorporate.

Have you guys run any scenario which is kind of the staff's most likely to occur scenario? Or are you scrubbing that as part of your review of any of these other ones?

MR. MILLER: We haven't done that as part of this review. This is all just a review of the utility filings. I don't know whether staff in energy efficiency division has done anything like that. I don't believe we've done any resource planning in our office on top of assumptions about energy efficiency that are considered --

MR. KELLY: So, hypothetically if the Public Utilities Commission sets a very large goal for energy efficiency or demand management or renewables or whatever, is there any point at which your process will be looking at the feasibility of that actually occurring within the timeframe that you're overseeing?

MR. MILLER: I don't think I can answer that.

PRESIDING MEMBER GEESMAN: And, again, as I did for Mr. Hemphill, I'll explain the distinction for you, Mr. Kelly, between the staff and the Commission. The Commission will be the body transmitting the report down to the CPUC.

MR. KELLY: Yeah, I understand that. I was just -- what it looks to me is when they build the resource stack they're going to be building assumptions which are based on these policy decisions that have already been made by the various agencies.

And I'm just wondering whether the feasibility of attaining those goals is embedded in any one of these resource scenarios that they're looking at, the staff.

MR. MILLER: In this review it's definitely pointed out as an issue that needs to be resolved before you can have confidence that you're authorizing the right amount of procurement. And I think some of the utility filings point that out. PG&E points out they need to have flexibility in resources, so you can make adjustment like in the authorization to procure resources, and the types of resources they procure, so you can accommodate changes, either realization the goals aren't going to be met, or realization the goals are going to be exceeded.

MR. KELLY: And the final work product, I presume, comes from the Commission to --

PRESIDING MEMBER GEESMAN: It comes from the Committee and I think --

MR. KELLY: -- will be -- reflect that?

PRESIDING MEMBER GEESMAN: -- we are quite mindful of the limits of precision in this area. And I understand there are differences of opinion as to where those limits lie.

But I would simply reiterate my own personal belief, we're not working with lasers here. At best we're working with crayons. And more probably we're working with paint brushes, the size of which you'd probably use to paint your house.

So you'll have to await our report to determine exactly how we've attempted to strike that balance. But I think we're quite mindful of the limitations in this area.

COMMISSIONER BOYD: The only hope I would hold --

MR. MILLER: If I do have a laser, I just don't know how to use it.

COMMISSIONER BOYD: The only hope I would hold out, Steve, is that as a result of this hearing, in assessing, you know, the resource limitations of this agency, maybe the Committee will ask for more analyses. A lot depends.

MR. KELLY: Um-hum.

MR. MILLER: We have acknowledged that uncertainties, either about the goals, themselves, or the ability to meet the goals, does affect the residual need. And this slide indicates, and there may be a dispute about this, that there might be new energy efficiency surveys or potential studies available, either completed this year, it is a separate question whether it'll be go through the PUC process and incorporate it into procurement that quickly. I doubt if that would be the case.

But, this goes to San Diego's point that the constraints or the goals being set for them can change. And they need to be able to flexibly react to those changes.

PRESIDING MEMBER GEESMAN: I guess I would also add, Steven, that this concept of residual need is also, I think, one of the areas that we have to provide some more thought on.

It strikes me that the mechanical arithmetic approach that our staff has taken tends to avoid questions like whether the state should pursue a policy in its procurement activities of encouraging retirements. Whether we should encourage a policy of remarketing existing resources that are under contract in order to achieve some level of retirements or turnover of the existing fleet of the facilities.

MR. KELLY: I know you know this, but obviously the importance of this is for example if the Public Utilities Commission is going to essentially defer to this process for determination of resource adequacy -- whatever they need, based on this study, you know, it will become important that the numbers, or the information that's presented in here is considered as realistically achievable, at least someplace, as compared to the stretch goals.

PRESIDING MEMBER GEESMAN: No kidding.

(Laughter.)

MR. KELLY: So we're working on realistically achievable rather than the stretch goals, I hope.

MR. MILLER: At least an understanding of the difference.

MR. KELLY: Good.

MR. MILLER: I'm about ready to go on to the next subject, so I'll give everyone warning if they have any lingering questions about energy efficiency.

Price-sensitive demand response. The goals were meant to provide an incentive and a benchmark for checking the progress. I'll quickly go through this. These are the goals established for procurement by the PUC. And 4 percent of annual system peak demand by 2006; and 5 percent by 2007 are the targets set; were relevant to this report, since the report starts with the year 2006.

As this slide points out, there's different ways to think about the megawatts from demand response. Enrolled megawatts is the name given to the maximum possible demand that could come from the number of customers that have signed up for the program.

Demonstrated megawatts is not quite having a smoking gun, that it's there when you need it. And it is a discounted number from enrollment. But it is based on some historical experience.

And expected megawatts would be a smaller number. And it's a combination of the information you've been able to collect historically. And I'll characterize this conservative judgment about what program savings can be counted on in the future. And the reason it's conservative is because all of the assumptions that go into these capacity resource accounting tables are conservative because the point is to determine whether you have confidence that you're able to meet your reserve margin targets or not, after you look at your demand and compare all your available resources.

Have I missed one? This version seems to have taken out a slide that I had in there.

Well, it follows from what I just said that I think the preference, at least in estimating residual procurement needs, is that the expected megawatts is what shows up in these tables. That's a different question all together of how the goals should be expressed.

They can be expressed in enrolled megawatts, but you need to understand how you get from one term to the other.

And apparently there is some confusion about that at the PUC right now. But I understand, and David Hungerford, probably after this slide, might be able to give some information about how they're at least starting to acknowledge and resolve that.

Is this provocative? Basically I'll go through this quickly. The goals we have assume that all customers could participate. But really only 40 percent of the load can now participate.

Some large customers were precluded from participating in demand response programs because they're already in reliability programs or other ones. And you have mutually exclusive options there as a customer.

In some cases the incentive to participate, from the customer's point of view, is small because they're not offered tariffs that are appealing to them. They must be voluntary, and the tariff has to be class revenue neutral.

In some cases there's significant expense involved, especially with large air conditioning load customers. And in addition to the expense there's a large effort involved to make these savings occur.

There's just -- customers are concerned about the stability of the programs. And some of the smaller customers just lack the expertise. And I think we're talking about transition -- the cost of them taking the action needed to -- getting the information and taking the action needed to get the savings.

Here's the missing slide; it was just out of order. Or I'm out of order.

Are there any questions about price-sensitive demand response?

Move on to the next category of preferred resource with a mandate. Part of this was gone over by Kevin earlier. The forms and instructions required two cases with different assumptions about the penetration of renewables. The reference case required 20 percent of the retail energy sales be from RPS eligible renewables by 2010. And an accelerated renewables case required 28 percent by 2016 for PG&E and San Diego, and 31 percent for Edison by that same time period.

To provide a benchmark staff developed, and these aren't repeated in the presentation, but do appear in the report, we call them attainment paths to each of those end points, just to check how the annual energy in the filings compared to being on track to meeting those goals in both cases.

Using those benchmarks I'll explain the results on the next slide. But staff looked at the project ID, the project output, and whether or not we felt it was an eligible renewable resource. And verified that the filings are okay.

And also found that the assumptions that they made, the IOUs made in their filings, are plausible. And the definition there is that they didn't use more than was technically possible. That's not a finding about cost effectiveness. We didn't do --

PRESIDING MEMBER GEESMAN: What kind of service territory assumptions did you impose there?

MR. MILLER: Where our technological potential numbers are by service territory; if the number seemed to exceed that, and there was other information given that it looked like they were actually counting on a resource that was outside the service area, then we found that plausible.

PRESIDING MEMBER GEESMAN: So you were permissive as it related to --

MR. MILLER: Right.

PRESIDING MEMBER GEESMAN: -- service territory delivery.

MR. MILLER: And normally if that occurred, then we checked to see, well, are they assuming there's transmission costs involved. And typically it was all consistent.

PRESIDING MEMBER GEESMAN: Okay, so you did then, at least by implication, assume that there was transmission, rather that deliverability would be required, and that that could potentially involve transmission investment?

MR. MILLER: Yes. And I think in all cases the utilities identified new transmission upgrades or interconnections would be needed. But didn't identify specific lines, or identify all the costs associate with it.

PRESIDING MEMBER GEESMAN: Okay.

MR. KELLY: Ross, could I quickly ask a followup on that?

MR. MILLER: Um-hum.

MR. KELLY: Did they identify transmission -- the transmission expansions, did they identify the timing of that to be consistent with bringing on the new renewables? Or was it simply we expect to bring on these renewables, and by the way, we need transmission?

MR. MILLER: Well, we'll jump down to San Diego. They can't get the transmission online in time to meet a graduated even path to attainment, but in their plan it comes online just in time. And if you double your renewable procurement that year, then you've met the target.

But their conclusion really is that they can't meet the 20 percent annual procurement target by 2010 without the new transmission line.

MR. KELLY: And for the other utilities they had a transmission upgrade plan that was consistent with meeting their estimated levels, or the targets?

MR. MILLER: Well, for Edison I don't recall in the text saying it was required, other than what's already been approved.

For PG&E it says here that they can meet the 20 percent with inservice area renewables, 20 percent by 2010. But it's going to require -- well, I think this is in -- they can correct me if I'm wrong, but I think again looking at least-cost/best-fit, they're going to be looking outside MP-15 if they have to go above the 20 percent. And that would require transmission costs, if not new lines. Or, as they point out, cost of renewable energy credits.

In both San Diego and PG&E's filings, the possibility of having unbundled RECs satisfying RPS requirement is held out as an alternative to the transmission projects, and the cost. But, of course, they would have costs, as well.

MR. KELLY: But if I understand you

correctly, for PG&E and Southern California Edison, at least, to meet the 20 percent target by 2010 you do not require, as a prerequisite, new transmission.

MR. MILLER: I think it -- go ahead, but I'd just interpret it, remember the reference case includes all their transmission projects have been currently approved by last ISO grid expansion plan. So, if you don't consider that new, then I think the answer is they can meet it.

MR. LaFLASH: Yeah, --

MR. MILLER: Yeah.

MR. LaFLASH: -- the slide captures it properly, 173 -- 30 million of generic transmission reinforcements in the service area consistent with a report that we filed at the CEC in 2003 that identified transmission cost ranking areas and which ones would need some amount of reinforcement to receive a certain amount of renewables.

So we don't know yet where those renewables are going to be proposed, so it is a generic number. It doesn't tie up any specific area.

MR. KELLY: So that has not been

approved by the PUC, per se?

MR. LaFLASH: Correct, there is no specific project tied to that. But the 20 percent is assumed within the service territory, would that amount of generic reinforcements within the area. Anything beyond 20 percent assumes we would have to go outside the territory, but we didn't specify transmission costs, because as Ross said, we would also look at if RECs were available at that time.

MR. KELLY: And those transmission upgrades that are included in that, those look like relatively -- those are not mega --

MR. LaFLASH: No, those are several minor transmission, and depending on the pocket that --

(Parties speaking simultaneously.)

MR. KELLY: -- within a year or two --

MR. LaFLASH: Correct.

MR. MILLER: What he said. Next time you ask me a question I'll just read my slide. I actually misunderstood what you were asking me.

So, to make that clear, PG&E does need more transmission to meet 20 percent by 2010. And they would need even more to meet the 28 percent by 2016 if RECs weren't available as a compliance option.

Many issues were identified by the IOUs related to RPS procurement. I've summarized some of them here. And first are above-market RPS compliance costs. And their rate impacts were identified as two separate issues. I've lumped them together here.

The fact that they think they're there and not sufficiently understood. This includes -- this tries to convey that your expectations of what the costs might be is different if certain conditions exist.

So the first one, what will the contract price of the renewable power be. That is a function of what the retailers obligations are individually and collectively. Whether they're increased, accelerated. Whether more retailers are brought under an RPS obligation.

Basically the cost of overall compliance is a function of everyone's obligation. The more the total obligation is, the more it's going to cost to satisfy it, as you march up the supply curve.

Also, I think San Diego pointed out that the marginal resources could be less productive than what we're seeing now. You might require higher cost technologies to comply.

Cost of new transmission interconnections. We were just talking about that. Nontransmission system integration costs. I think Kevin pointed out that there's a workshop, I think, next week on that issue.

San Diego pointed out indirect integration costs, firming capacity, and just the cost that the intermittence of some of the resources supposes, as you're trying to deal in the wholesale market, making purchases and making sales, if you're long.

Whether the public goods charge funds are adequate to pay for the above market component of the contract price is an issue for an individual IOU's certainty about whether they can meet their goals. It's also a question whether the overall statewide goals can be met, where supplemental energy payments are required. They're not always required.

Other issues are deliverability. We mentioned -- and this is actually different from the cost of the transmission, but just the fact can you do it. Can you get it licensed. System reliability and operational consequences. Again, it's different than the cost of integration. There's going to be a tradeoff between how much you're willing to pay and how much you're willing to have reliability or other operational attributes affect it.

All pointed out that allowing unbundled RECs for RPS compliance is an alternative to some of these issues. And that's being actively considered at the PUC. And I expect at the Legislature.

The theory there is allowing RECs that are designed for this purpose would make compliance across all retailers more efficient. And environmental beneficial, I think that applies to having to build less transmission.

And Edison pointed out that RPS targets should not be increased until we've got a better idea of what all the LSEs progress they're making toward the statewide goals.

MR. KELLY: Ross, on that latter point, is there any process or mechanism in place to determine what the impediments are for the utilities to achieve these goals?

I mean that's kind of a policy declaration that's being made there, so I'm wondering if there's a process to even to make that, existing RPS targets should not be increased.

MR. MILLER: I'm just reporting what Edison has in their filing. And I believe that is a policy statement.

I also understand, just before I came down here, that there's a ALJ Allen, a common opinion out on participation of LSEs, community choice aggregators, small utilities and multistate utilities in the RPS. And it looks like there's a commitment to move forward on that.

Any other questions about the renewable resources?

MR. PIGGOTT: This is Jack Piggott from Calpine. Can you hear me?

MR. MILLER: Yes.

MR. PIGGOTT: I just had a question about how this relates to the tables in the back. I was looking at on page B-2 where PG&E's renewable, it says total existing and planned renewable energy, it seems to diminish.

MR. MILLER: The tables that we included

in the report are tables that were offered by the utilities for public disclosure. One feature of those tables is that there is no line that tells you exactly what the future renewable procurement will be. That is spread across three or four lines, depending on the utility.

So that line you're referring to is the expected future output from existing renewables and renewables that they expect to get from procurement authorizations they've already been given. Not renewables that they would understand they need to get to meet whatever the target is, and then be given authorization to procure in the next cycle of procurement.

So the generic -- at the bottom of both the capacity and the energy forms, the residual need is expressed in terms of generic new renewables, generic peaking, generic load following summer, load following year round, and baseload.

So that generic new renewables, that incremental amount they have to get authorization to procure is not included in that line.

And so you might expect some degradation over time from those resources if you're, for example, geothermal steam field depletion or some of the older units going away; or just contracts expiring.

MR. LaFLASH: It's the latter.

MR. MILLER: It's the latter PG&E says, contracts expiring. That just moves them into the new category. You don't already have them in the portfolio, you need to go out and do something to get them, or something else.

MR. PIGGOTT: I guess I find from this whole report that it lacks specifics, I mean it's such a broad summary and lacks so many specifics, that it's difficult to comment on.

MR. MILLER: That made it difficult to do, also. Commissioner Geesman referred to the confidentiality constraints that we're working under. And the new aggregate tables that Kevin referred to earlier actually do separate out that line. I don't have them here in front of me, but they were put on the web, I think, yesterday.

So, I believe it separates out the new generic renewable procurement as a line item.

MR. PIGGOTT: Okay, and that's not part of this report that --

MR. MILLER: That wasn't part of this

report, but it's definitely related to it. It's based on the same filings. I mean this is just a procedural distinction. That just came out yesterday, so I don't think we're really allowed to have a public workshop on it the day after.

But I believe, as Kevin pointed out, there's at least two future workshops where that will be the subject, including what we're calling the statewide and WECC resource outlook report. I think that will be out July 11th.

PRESIDING MEMBER GEESMAN: Jack, this is John Geesman. As I think you know, the Commissioners are also confined to seeing what you're seeing in this report. So we will make the best of it, and certainly welcome your comments and those of any of the other parties as to what interpretation we should provide to the data that has been allowed to be public.

MR. PIGGOTT: Okay, thanks.

MR. MILLER: Distributed generation. As I mentioned earlier there's no express mandate for distributed generation. There is a line item in the resource plans for that, and the utilities included their best estimates of growth in DG resources.

I'll skip to the bottom line here, is there wasn't quite enough information to determine how feasible those forecasts are. We don't really have any reason to think they're not feasible. But, considering the focus of the report and the relative small amounts of DG, that this uncertainty doesn't really cause a big problem when you consider the magnitude of the resource need that we're talking about.

COMMISSIONER BOYD: This is a big problem to me, and I chose not to ask each utility when they came forward, but to save it for this slide and this point in time. And just have a general flogging of all.

This issue has a priority in all the areas you mentioned, the Integrated Energy Policy Report, the Action Plan, in legislation. It's obviously not well embraced. And you said it has no mandate, which is true.

And that all those added together re-raise policy questions for policy folks, I think, about whether this is a policy-starved area, and what is it going to take to light a fire in this boiler, or under some people, or what-have-you, to fulfill the very high priority that it's been given in the loading order, et cetera.

I don't have the answer. This doesn't give us an answer. It just gives us some facts or lack thereof. So, to me this is an issue on my list that this policy body is going to need to address. And I'll let it go at that.

MR. MILLER: Moving on to the general category of existing and planned resources, of which the existing and planned renewables is one. I'm just not focusing on it here because those were included in the discussion of renewables earlier.

This just shows the relatively large contribution of the energy and capacity from the existing DWR contracts to the portfolios of the IOUs. And it shows that those contracts are expiring. And the conclusion there is the utilities are going to have to be authorized to procure resources to replace them.

And this degradation of this supply does show up in the estimates of residual need, I'll call it, in the resource plans.

A point here is that the replacement resources will be subjected to the procurement, least-cost/best-fit tests and other constraints.

So we do expect the sources that replace these to better meet the portfolio needs, and also will have to confirm to the new resource adequacy and deliverability requirements that didn't exist when these contracts were signed.

The QF contracts, basically across the board the utilities didn't assume any more than 10 percent of their existing QF contracts would have to be replaced. So, ultimately the uncertainty about what that causes in estimating what the residual need is, is relatively small.

That's not to say that there aren't policy issues being considered at the PUC right now about what are the terms and conditions under which existing QF contracts might be extended or the extent to which procurement process will be relied on to replace them.

MR. KELLY: Ross, this is Steven Kelly. What was the basis for the 10 percent number? What was the rationale behind why 10 percent? Why not 2 percent or 12 percent?

MR. MILLER: Well, the rationale was each of the utilities -- I think San Diego basically, they had one -- already renegotiated one of their contracts and the rest they assumed they would be able to, just looking at the particulars of the contracts.

And with PG&E and Edison, I think they both did the same thing, you know, looked at their portfolio of QF contracts, they're familiar with them, and made some estimate of which ones were likely not to be -- which of those that their contracts were expiring were not likely to be renegotiated.

MR. KELLY: But on that latter point was because they wouldn't want to renegotiate new contracts? Or they wouldn't be able to, or --

MR. MILLER: They didn't specify that.

MR. KELLY: -- I mean I presume everybody who's got one would like to extend it, but I don't know.

MR. MILLER: They didn't specify that.

MR. KELLY: They didn't specify.

MR. LaFLASH: That was litigated in last year's long-term plan -- The 10 percent number for PG&E was actually the case that we had in last year's long-term plan, and we litigated in that and was found to be a reasonable estimate.

I mean it's not every plant lasts forever, so it was assumed just some level that there would be some attrition.

MR. KELLY: So that's basically the mechanical attrition of the units, themselves, rather than --

MR. LaFLASH: Or parties that may choose to sell to other market players, just attrition of contracts.

MR. KELLY: Would that have changed if there are no other market players?

MR. LaFLASH: We didn't speculate on that at the time.

PRESIDING MEMBER GEESMAN: When you speak of last year's long-term plan, I believe you're speaking of your long-term procurement plan at the PUC?

MR. LaFLASH: Yes, we are; the one we filed in July and it was approved in December of last year in 12-04, 12-04-'8.

MR. KELLY: Thank you.

PRESIDING MEMBER GEESMAN: Thanks.

MR. ANDERSON: If I could just clarify San Diego's case. Right now all of our QF contracts, there's only one contract that expires during this planning period. All the rest of them we have under contract throughout the planning period.

That one QF is relatively small in our service territory. For whatever business reasons they have, they've tended to want to do five-year contracts and we've been able, at the end of each five-year contract, renew it.

So, for San Diego we have assumed that all of the QFs in our service territory remain running. And we don't take the 10 percent discount.

MR. MILLER: Thank you. The next slide is that qualitative description of the net open positions, which is the phrase we're using here. It's probably not exactly accurate because the open positions are very detailed descriptions of specific commodities in specific markets. But we're using that term to identify if you do these supply-and-demand energy and capacity tables what do you end up with as a gap when you subtract the estimate of your supply from your estimate of your demand.

What we find, and I think can cite publicly, I hope -- it's too late if we can't -- is that as we mentioned before, the DWR contracts do provide a large amount, roughly one-fifth of the current energy requirements, and those are going away relatively soon.

So what will those be replaced with, and what other resources will fill the growing demand? That's governed by the procurement proceeding, all the policy constraints, and least-cost/best-fit objective. So, the real answer to that question is nobody knows yet.

We do expect that as the energy efficiency programs goals increase over time and more of the total energy will be provided from those resources, we know that the renewable procurements are increasing from today's targets to the maximum targets that are specified in the program. The same is true of price response of demand.

But at some point the utilities, after the procurement plans are approved, are given authorization to put out RFOs for renewable and nonrenewable power and subject the bids to least-cost/best-fit evaluation.

That was confined mostly to the idea of baseload energy. From day one the utilities have short-term, mid-term and long-term need for dispatchable and load-following or shapeable capacity. And they're being authorized now through the current cycle of procurement to put out RFOs to procure portions of that. And basically this is the start of the next refresh cycle for those directions for the utility procurement.

An important point utilities made is that there does have to be flexibility in procurement, and there has to be contingency plan, should the resources that are thought to show up end up not showing up. Whether that's a preferred policy resource or any resource. For example, the nuclear power plants could go out tomorrow.

This starts a section on impacts, and I am trying to keep this to one slide or commenting on one slide per section, but these impacts or uncertainties were all specifically asked to be addressed in the forms and instructions.

The utilities were asked to look at the resource plan cost estimates of the different scenarios. And our conclusion is the information that was provided is not really useful for quantifying the scenario cost impacts, or therefore comparing them. There were a number of reasons for that, which are listed here.

That's not to say they weren't complete worthless. I thought the narratives description of the potential cost issues are very well thought out and important. Unfortunately, we just don't have the qualitative analysis to understand it as much as we'd like.

PRESIDING MEMBER GEESMAN: I'm not certain what you just said.

MR. MILLER: Well, if you look at the numbers, and we included them in appendix D in our report, we basically say don't pay much attention to them because significant -- for these reasons: either significant categories of cost were completely omitted from the accounting. For example, between two cases where you knew there was a new transmission line had to be built, in some cases the cost of that transmission line was not included in the resource cost estimates. So that means that's not the total picture; we've got to be careful to not be too influenced by those numbers.

MR. KELLY: Ross, can I ask you, in some cases it was included and in some cases it's not, so there's a lack of consistency?

MR. MILLER: In some cases it was

included and in some cases it wasn't.

MR. KELLY: So all the renewables have been included probably, and nonrenewables probably don't?

MR. MILLER: I don't believe all the renewable cost of transmission were included. I think it's not known, especially for -- you're thinking of the one slide where PG&E did identify a certain quantity for transmission. They identified that, but they didn't put it in that table.

And San Diego, I don't believe, identified the cost of the transmission project. In fact, San Diego's resource plan cost estimates for the reference case and the accelerated renewables case is a good example. Those two resource plans cost exactly the same.

And even though the narrative says we're concerned about all these costs, transmission, the reason they're the same, you know, upon inspection is that they left out the transmission cost difference, and they also made the input assumption that the cost of renewables is the same as the cost of nonrenewables.

So the present value of the cost between those plans, under those assumptions, comes out to be identical. So the question is how much do you want to be influenced by that table.

So I do refer back to slide 15 where a lot of cost-related issues were mentioned. The cost issues are not confined to renewable policy; it's a factor of -- and we'll get into this later with fuel prices, other regulatory uncertainties. They all ultimately have cost impacts.

The next area is local area reliability assessment. I'm careful here to say that the utilities say that it's the ISO's, not the LSE's, obligation to meet local area requirements. And I've heard that in other forums.

San Diego specifically points out the decisions that have given the ISO that responsibility. And, you know, the question is to what extent that will continue to persist throughout the planning period.

As at least Edison and San Diego point out, is that these resources are dispatched for grid reliability; they're not dispatched to optimize the individual LSE's portfolio. And Edison and I think all the utilities point out that they really don't have the information about the local reliability, at least not up to date. And not the input assumptions that would be required to make a future assessment of what LAR requirements are over the next decade. The ISO is in the position to do that, not the individual LSE.

MR. KELLY: Ross, on that for dispatch for, quote, the needs of the grid, for example if there was -- the ISO became aware of an under-scheduling issue or problem, wouldn't the ISO dispatch some of its units under an RAR to meet load?

MR. MILLER: Right. So whether it's for a particular physical problem or market power --

MR. KELLY: Or underscheduling.

MR. MILLER: Underscheduling, right. And so I mean the utilities are not completely unaware of all this. So they have made either rules of thumb, or put in placeholders. They realize that these problems exist and they are going to be responsible for contributing to it.

But San Diego's comment here at the bottom is, and I believe Edison, at least, if not PG&E also, think that because it is a control area requirement, then the cost of whatever's required to meet those requirements should be shared across the control area among customers who benefit.

How to do that, I guess, is the trick.

MS. JONES: I have a clarifying question. It says LAR resources are dispatched for the needs of the grid. Not the grid on a larger basis, you're talking about just the local area requirements?

MR. MILLER: Right, the local area grid requirements.

MS. JONES: Okay, thank you.

MR. MILLER: Or maybe those are mutually exclusive terms. You're right, local area requirements.

PRESIDING MEMBER GEESMAN: I think we spent a lot of time on this last year and learned that they were mutually exclusive.

MS. JONES: Okay.

MR. MILLER: So that's my error. Any other questions about that?

MR. KELLY: Ross, I do have one question on that. Under the second point under the first bullet, where the LSEs, individually, cannot know the type, location or amount of future LAR resources. In the context of what you described in the last slide, which basically said there's no consistently on the application of costs of cost resources, I'm wondering how the utilities implement least-cost/best-fit methodology in any scenario when they don't know --

MR. MILLER: Taking this factor --

MR. KELLY: -- the type, location or amount of --

MR. MILLER: -- how do they incorporate this factor --

MR. KELLY: -- required future LAR resources. How --

MR. MILLER: Yeah.

MR. KELLY: How is that accomplished?

MR. MILLER: I'll give the general answer. I think as best they can. The specific answer, I think, might be subject to confidentiality constraints. So the simplest thing for me to say is I don't know.

MR. KELLY: Well, I think it's --

MR. MILLER: The utilities can -- I think that's a good question.

MR. KELLY: It's a followup to Commissioner Geesman's --

MR. MILLER: Yeah.

MR. KELLY: -- point this morning earlier at the beginning about the need for information on the methodology about how they make choices.

MR. MILLER: Right.

MR. KELLY: It would be helpful if that is publicly available so people could understand that. But for you guys, who apparently have access to redacted information, to not have a good understanding about how they can make a least-cost/best-fit evaluation for renewables or for RAR or anything else, when they say they don't know the type, location or amount of required future resources is beyond me. I don't know how they do it. And I'd be interested to know the methodology to make that happen.

MR. HEMPHILL: This is Stuart Hemphill from Southern California Edison. I'd be glad to talk about that. What we're talking about here is local area reliability, which is a Cal-ISO function. And in that area we don't know, and the Cal-ISO cannot provide to us in the current rules, the information necessary to specifically meet their needs.

When you talk about least-cost/best-fit

that's meeting our bundled customer needs. That's a retail function. And that is something we can know and we do know. And it's something that we do on a day-to-day basis.

So these are two completely separate functions. What we try to do in our long-term RFO is try to define something that we think will help the ISO do its job. And so we try to define particular areas where we thought the ISO might need new generation. And we tried to think about the types of services the ISO might need to do its job.

And so we're taking our best estimate of something that we think, and probably know, that Cal-ISO might need to meet their objectives. But these are two completely separate procurement objectives.

MS. JONES: But isn't it true that in procuring future resources, depending on where and what types of resources they are, you can either increase local area reliability or decrease the need for local area reliability? So they're not independent.

MR. HEMPHILL: If you're talking about general bundled procurement, we can certainly state a preference as to where we would like it located. Whether that actually helps the Cal-ISO or not is a question we can't answer.

We can attempt to define criteria that we think will help the Cal-ISO, and that's what we're doing in our long-term RFO.

PRESIDING MEMBER GEESMAN: This problem is probably best thought of in a time dimension. And I think that the issues were pretty clearly raised last year in your filings with the CPUC probably about midyear. And I'm sorry, I don't know the docket number.

But when certain responsibilities were shifted by PUC directive from the ISO to you, I think the issues were pretty well fleshed out.

My impression from this slide and the summary of your filings with us, along with your comments today, is that those issues still remain. They've not really been satisfactorily resolved.

MR. HEMPHILL: Yeah, like I say, we have rules of thumb about what we think the Cal-ISO needs, and we are attempting to implement those. And, you know, hopefully we'll have, you know, good review by Cal-ISO to make sure it's something that's needed by them.

But we're trying to do it in the context of the information available to us.

PRESIDING MEMBER GEESMAN: Thank you.

MR. MILLER: Another requirement of the forms and instructions was to discuss the potential impact of a greenhouse gas adder on bid evaluations and procurement.

This is a very brief summary of what was provided. And, you know, I'd have to say that this has been ordered to be done in the current round of procurement. So a lot more detail on how this is done is getting worked out by the utilities and described, at least to the procurement review groups, and I would expect, if not already, disclosable characterizations of those methods will or have already gotten out.

Looking at what was provided in the filings here, basically different approaches are being taken; and whether or not they're consistent with what they were told to do, is hard to say. They were basically told to include it.

PG&E doesn't start out with the specific cost of emissions, even though the cost they were told to use has been identified by the PUC. They use a tipping-point analysis where they just compare the bids and see how close they are. And they have a range of costs of what the adder ought to be. And if the difference between the winning bids and the losing bids is anywhere close within that range, then they'll re-examine the bids and look more closely at how those costs might change their decision.

PRESIDING MEMBER GEESMAN: And how is that inconsistent with the directive from the PUC?

MR. MILLER: I don't think it is inconsistent. I mean if they were to use a different number, if they were not to use it at all, that would be inconsistent.

MR. LaFLASH: I can clarify that. When we started this process in probably November last year, we filed the various filings throughout the first four months. The directive from the PUC was to use a range of $8 to $25 a ton. They have since come down and said use $8.

So the tipping-point analysis was what we were using at the time we filed this. Things have since been clarified.

PRESIDING MEMBER GEESMAN: Thank you.

MR. MILLER: Edison's method is described as either giving benefit to any they say contractor, it's a resource that you're evaluating its bid, that would decrease greenhouse gas emissions in its stack, or I assume its portfolio.

And any bid that would increase greenhouse gas emissions then it would get an emission cost attached to that bid. And where specific cost was used, then I'm assuming they're using the number that was specified by the PUC.

PRESIDING MEMBER GEESMAN: I guess I don't follow how that is consistent with the directive from the PUC.

MR. MILLER: Well, I can let Edison answer the question, but I haven't found any way that it would be inconsistent.

MR. HEMPHILL: We're asked to evaluate the impact of greenhouse gas emissions by including a $8 per ton adder in the evaluation process. And we certainly are doing so.

I think the best way for me to describe it is in the written documentation that I promised you.

PRESIDING MEMBER GEESMAN: Okay. The concern I have, Stuart, is the way this bullet describes it, it looks to me like you are comparing a bid to your current supply stack.

Whereas I had understood the PUC directive to be a comparison at the margin of two incremental bids.

MR. HEMPHILL: I believe both bids would have the impact of greenhouse gas emissions incorporated and evaluated in their bid.

PRESIDING MEMBER GEESMAN: Okay.

MR. MILLER: Well, and this is my characterization, so it could be wrong. And what I thought this referred to was what they're actually doing is looking at the emission costs associated with a portfolio with bid A, and then emissions costs associated with a portfolio with bid B in it, and comparing those.

And that way you can use $8, you can use whatever number you want. But you're also getting the induced effect of your existing resources in the portfolio that have their emission profiles changed by the addition of either bid A or bid B.

That's the way we used to do it when we did -- when we internalized this externality in our resource planning in the '80s. I can recall that, long ago.

San Diego didn't have a specific method that they described, but they did specify features that a method should use. And I've listed some of those attributes here. If there's any questions about them I direct them to San Diego.

The last bullet is because these are so different we're not really sure of the pros and cons. We don't really have any reason to think that they're not all compliant or responsive to the PUC's direction. We offer it, you know, if the PUC sees that and thinks that something is not right, or the Energy Commission does, then that's the state of the information as we have it today.

I mentioned before that when the least-cost/best-fit criteria was directed to be used in procurement in the December '04 long-term procurement decision, it didn't really define what that was. And I think it left open that that definition would change over time and might vary across utilities. There might be different reasons for significantly different portfolios to define the specifics of a least-cost/best-fit decision criteria differently.

PRESIDING MEMBER GEESMAN: Yeah, but is it a methodology, or is it a bumper sticker?

MR. MILLER: I think it's a methodology from what I've seen.

PRESIDING MEMBER GEESMAN: Okay, and

that's what we'd requested.

MR. MILLER: A fairly complex one, and is -- I don't think you could characterize it as a spreadsheet that you could put in bids and know what the answer's going to be. I think there is judgment involved. And that's one of the reasons that -- that's one of the aspects that the public review group has asked to weigh in on, is the judgment. Too much judgment, too little judgment, is the quality of the judgment acceptable --

PRESIDING MEMBER GEESMAN: Who is the public review group?

MR. MILLER: I'm sorry, the procurement review groups.

PRESIDING MEMBER GEESMAN: The nonpublic procurement review group.

MR. MILLER: Yes. The noncommercial market participants that participate in those.

PRESIDING MEMBER GEESMAN: Well, we're looking forward to an explanation of just what that methodology that each company uses is. And we'll wait until we get that before making any pronouncements about it.

MR. KELLY: Ross, can I just add one thing, because I'm not sure that I'll actually be able to see the methodology.

But, I've always -- I'm a little confused here -- I've always kind of assumed that the utilities would get two bids and they would have some mechanism to estimate what the emissions by tonnage would be over time. They would impute an $8 per ton value to that over time. And then net present value it. And then take the winner. Is that what's going on?

MR. MILLER: When I think of the term adder, that's what immediately comes to mind. What happens there is, and this is, you know, part of the details of comparison that we tried to deal with in ER90, 92 and 94s, well, what if you have, how do you differentiate the cost of say a new combined cycle with whatever the latest emission control is, and a bid that might be a ten-year contract with an existing steam boiler unit.

One is more efficient than the other. One produces less global climate change emissions than the other. And the question is shouldn't the one be given -- if you put the emission costs on both of those, one will appear to perform better with respect to the least-cost/best-fit criteria than the other.

MR. KELLY: Right, but you're applying that $8 on a per-ton basis.

MR. MILLER: That is a head-to-head comparison.

MR. KELLY: So if you have an estimate of what that per ton is per bid --

MR. MILLER: Right.

MR. KELLY: -- unit, you can do it. But I can't tell if they're actually doing it that way. I mean I don't know how they're doing it, but --

MR. MILLER: And that's what we're looking forward to seeing the details of.

Well, another aspect of that is the bids don't necessarily provide the same amount of annual energy, the same performance. And by looking at its impact on the total portfolio you're able to capture climate change benefits that are induced in the way the other resources are displaced, or the performances otherwise changed.

PRESIDING MEMBER GEESMAN: As modeled.

MR. MILLER: As modeled.

PRESIDING MEMBER GEESMAN: I didn't see in the PUC December procurement decision a directive to include this adder in bid evaluations on a modeled basis.

MR. MILLER: No, it doesn't say that.

Going to the next subject, natural gas price forecasts. I'm going to show you some slides here that have information that we've added since the report was published for two reasons.

One is since the report was published it's been clarified that the forecasts from 2009 to 2016 can be disclosable. We didn't have that clarification when we published, so they were left out. Just described qualitatively.

And the other addition is that we have a new staff forecast available now that we didn't have then. And because the forecast staff used as a benchmark for the plausibility of the IOU forecasts was part of our report, we felt we should let people know that we've changed that benchmark.

The different ways to forecast natural gas prices were all employed in the utility filings. Nymex future quotes were used for short-term and even longer term price forecasts in some cases. The fundamental market analysis models were used. And different types of time series or projections based on historical price trends were also used.

I'm going to go on to this slide. This slide, if I can get this to work. Without these three lines this is, I think, table 7-3 in the report. And these are Nymex quotes that were taken at a point of time later than when the utilities made their filings. And the staff point there was because over this period from when the utilities did their work and we did our review, Nymex prices, future prices were going up.

And what those quotes are tends to determine the starting point for your forecast, whether you switch to fundamental model or a trend analysis. It has a material effect on what you're forecast ends up being.

These were the Nymex quotes at the time we were reviewing it. This is the staff preliminary price forecast that we compared qualitatively against the utility forecasts. And these are the utility forecasts which we couldn't divulge quantitatively at the time.

So we did describe that Edison and San Diego had a similar trajectory but started at different points. And that was a function of the

Nymex quotes they used, which were down lower here. And PG&E's was quite different in that it never did increase over the planning period.

The next slide here is taking that same slide and adding the staff forecast, which was just published, and just, you know, one observation is that it's starting to close the gap between the original staff benchmark and at least the highest of the three utility.

Now, I think the staff concluded that the methods that each utility employed were rational, but there's so much variability in the outcome depending on which quotes you're using; whether you use a single quote; whether you use a rolling average of quotes. And also whether you switch to a fundamental forecast or some type of trajectory based on implied heat rate.

So the bottomline is the results can still be all over the map even if people generally agree that the methodologies are not implausible.

PRESIDING MEMBER GEESMAN: And we're going to have a workshop in July --

MR. MILLER: Right.

PRESIDING MEMBER GEESMAN: -- on the gas forecast.

MR. MILLER: Electricity prices, basically the wholesale electricity price forecast is a function of the gas price you put in it largely. So we backed out the individual gas price forecast and just put in a staff forecast for the purpose of assessing the electricity price forecasting technique. And we basically concluded that those were fine given the input assumptions that were being used about gas.

Forms and instructions asked for the utilities to comment on what would be the impacts on their portfolio in procurement activities if the large nuclear units were to retire early. And Edison and San Diego provided an assessment of what would happen in the absence of San Onofre Nuclear Generating Station Units 2 and 3. And, you know, the loss of 2100 megawatts plus the assessment that much of the replacement capacity would need to be inbasin because of local reliability constraints. And also to maintain the import capability.

Obviously if this were replaced with gas-fired resources there would be higher gas demand. And it's possible that a new 500 kV transmission lines or static VAR compensators would be among the upgrades to the transmission grid that would be required to mitigate negative impacts on the transmission system.

There was no filing about Diablo Canyon made.

PRESIDING MEMBER GEESMAN: With respect to SONGS --

MR. MILLER: Unless I missed it.

PRESIDING MEMBER GEESMAN: -- were the transmission upgrades identified or quantified in terms of costs?

MR. MILLER: No. Neither by project or cost.

PRESIDING MEMBER GEESMAN: And was there any explanation from PG&E as to why they did not make a filing?

MR. MILLER: I think they're about ready to provide it.

PRESIDING MEMBER GEESMAN: Okay.

MR. LaFLASH: We misunderstood the request at the time because we had already had our steam generator replacement program approved by the Commission. But we are more than willing to file that information. We had all that information already on file at the Commission in that proceeding, so we'll provide copies of that.

PRESIDING MEMBER GEESMAN: That'd be helpful. Thanks.

MR. MILLER: Edison was also asked to look at the impact on their portfolio if the Mojave Generating Station were returned to their portfolio. And this describes what the impact would be.

This is pretty much right from their filing, and if I could try to check my understanding of it, because it's perceived to be a low-cost energy resource it would be dispatched at a high capacity factor. So you'd find it displacing energy from capacity resources of equal amounts to a greater degree. So you'd expect there might be some, if you could realize them, depending on, you know, contract conditions, there'd be some energy cost savings.

And it expressly says that it would be avoiding the fixed cost of the other resources you'd otherwise get.

I don't believe their filing says one way or the other whether they expect the energy cost differences and the capacity cost differences to be greater or less. I think you obviously have to wait for procurement results to know that.

MR. KELLY: Ross, Steve Kelly again, real quickly. I mean earlier in the slides there was an indication that the utilities primarily needed dispatchable resources, not baseload resources.

MR. MILLER: Right.

MR. KELLY: And I presume from that that any baseload resources that would be bidded would be evaluated in some manner, unknown to me, but in some manner against the need for dispatchability. Is this facility being treated the same way? Because here you're suggesting that it's going to displace the dispatchable resource that they need, but I don't see the other baseload units being evaluated in the same manner.

MR. MILLER: I think, and Edison can correct me, Mojave is not in the resource plan at all during the planning period 2006 to 2016. So if it is going to come back into service it exists out there as an option in the market. And if Edison, looking at its resource needs, thought it was attractive to take this option, it would have to either go through the procurement least-cost/best-fit competing with other options where portfolio fit, including -- this is a baseload resource and we may not need baseload energy. Depends on the comparative economics.

MR. KELLY: Is that Edison's understanding, that this facility --

PRESIDING MEMBER GEESMAN: Let me jump in here, Steven, because I think Ross may have been a little speculative. My recollection is that this is a scenario that ORA asked us to look at, so that it is constructed at their suggestion. How the results would be applied by the CPUC, I don't think we have any insight into. Unless you'd care to comment on it, Stuart.

MR. HEMPHILL: Well, I can at least describe a few things and clarify a few things. I have not been shy over the past two years to talk about what types of needs we have over the next decade.

We do have a primary need for dispatching dispatchable peaking and intermediate resources, but that subsides at the end of the decade.

Usually when we're asked to look at Mojave, and we've been asked many times to look at it, it's around the 2010/2011 timeframe when we actually do have a baseload need.

The big concern we have about Mojave is we don't know what the fuel costs or what the water costs are. There are also some permitting issues associated with Mojave. And so it's a very difficult evaluation to be able to get your arms around.

PRESIDING MEMBER GEESMAN: But you did make some assumptions about fuel and water and refurbishment costs in this scenario?

MR. HEMPHILL: I believe we provided a description here. We've done this type of evaluation in PUC proceedings on this topic over the past couple of years.

PRESIDING MEMBER GEESMAN: Thanks.

MR. KELLY: Stuart, real quick, is this facility -- when you evaluate it is this facility being run through the same least-cost/best-fit methodology that you're applying to everything else?

MR. HEMPHILL: We use, when we evaluate any resource we always look at a least-cost/best-fit evaluation.

MR. KELLY: But it's the same methodology?

MR. HEMPHILL: Yes.

MR. MILLER: I think that's all I meant to imply, that either it would have to go through the established procurement proceeding in competition with other resources, or it would be an application that Edison made, which would effectively be subject to the same comparison.

PRESIDING MEMBER GEESMAN: Yeah, I think you guys call those unanticipated fleeting opportunities.

MR. HEMPHILL: Yes. There's a lot of those still.

MR. MILLER: Getting close to the end here. A specific scenario was specified for assumptions about departing load. And I'll call it here the low load case.

Basically by 2012 75 percent of the 500 kV or greater customers were assumed to be -- left bundled service. Neither Edison nor San Diego actually filed that case. San Diego did file an estimate of what that load change would be, and a description of how their portfolio might be affected, which I've included here on the slide.

An important point they make is that just because this load isn't in their bundled customer, it's still in the basin, and would have no effect on inbasin resources or transmission requirements.

As far as San Diego's portfolio, if that much load were to leave then they'd end up with fairly high reserve margins.

PG&E filed, if you look at their three cases, their reference case, their preferred case, and their noncore case, they describe a range of load that's basically what their current direct access is to 50 percent in their preferred -- 50 percent of this class of customers of greater than 500 kV leaving, and 75 percent in this scenario, which they did file a core/noncore case.

And their main point about this is this is possible, without saying how probable either case is, but just the fact that it is possible argues that the utilities' procurement strategies ought to be flexible enough and include long-term, mid-term and short-term contracts that could be adjusted as they experience these types of major shifts in customer base.

PRESIDING MEMBER GEESMAN: You described San Diego's explanation. Did Edison provide one?

MR. MILLER: I can't recall if they did.

The next slide basically, I guess, explains. Their position is that they don't have the information to make a reasoned estimate. So rather than provide it, they didn't; and caution that, you know, procurement -- and this is an important point that if we're talking about knowing how much resources we have to authorize to procure, these are the type of speculative assumptions we really need to get a better handle on.

And this goes to the issue of, as San Diego points out, under current policy the IOUs are the providers of last resort in their distribution service territory. So they could end up having to serve this load even if they're not authorized to procure resources, assuming it's there.

Sam Diego identified the issues about the threshold of demand to qualify for direct access, ability to aggregate the load, the timing and the notification rules for switching back to bundled service really need to be resolved before you can come up with a reasoned estimate -- I'll use that as a term -- of what the departing load potential might be. And you need to have that before you can estimate what the resource requirements would be under those conditions.

But, you know, they recognize they do have some jeopardy here because ultimately if and when it happens, they'll be expected to provide the resources for it, if the load returns.

PRESIDING MEMBER GEESMAN: Doesn't sound like any of the companies placed reliance on some of the language from the PUC's December decision about exit fees and disallowances of any cost shifting and forcing obligations to go along with departing load.

MR. MILLER: I didn't see anything in the supply filings. Any questions or comment on that?

Last category is transmission. This had a variety of requirements. One was expressly if the reference case included a major new transmission project we wanted a case without that project for the purpose of identifying what the impact of the transmission was.

PG&E included in all of its scenarios just the transmission facilities that have already been approved in their grid expansion plan. But did point out that in order to achieve some of the other cases, particularly the -- well, actually in order to achieve their current 20 percent by 2010 RPS requirement, they would need additional transmission. And on top of that some interconnection costs. And there would be other transmission required for the higher obligation. That wasn't identified, or the price estimated.

Edison's case includes, in the reference case includes the Devers-Palo Verde 2. We've talked about this a little bit already. There's an application at the PUC for approval of this project right now. We mentioned this in the context of resource plan costs. They've directed us to look at the IOUs area analysis of this project, rather than the more narrow portfolio look that the forms and instructions describe.

PRESIDING MEMBER GEESMAN: Let me break in there, that we have been pretty complimentary of the ISO analysis of the Devers-Palo Verde 2 project. The criticisms that we've talked about in earlier workshops have tended to criticize the ISO methodology as unduly conservative, which I would suspect would only go to emphasize that there's more benefit to the project in terms of the methodology that our staff, our transmission staff has thought should be applied than even the ISO analysis has shown.

MR. MILLER: I'm mindful of the comments made about staff's mischaracterization of the filing that Edison made with respect to Palo Verde-Devers 2. So if there's anything in this slide that's not correct, let me know. I don't think I repeated the offending passage in the report in this slide.

They did note that the accelerated renewables case would require additional transmission and operation challenges. And I believe in Edison's cost comparison of cases they did include some estimate of costs for transmission, but with the caveat that it's not the total -- they don't believe it's the total cost because there's information about -- the specificity is just not there or known to come up with a dependable cost estimate yet.

MR. KELLY: Ross, does the Edison reference case include the Tehachapi line?

MR. MILLER: I don't recall it specifying that. That doesn't mean it wasn't there.

MR. HEMPHILL: Maybe I should just sit

by you, Steve.

MR. KELLY: There you go, grab a seat.

MR. HEMPHILL: Actually I will. What we did when we looked at our different scenarios was to look at things that we thought would change between the scenarios; and also to look at those things that would impact our overall procurement.

And for the Tehachapi line we included it in every scenario. So there's really no differential between the scenarios.

MR. MILLER: San Diego. As we previously heard the reference case does include a new 500 kV bulk transmission project which they say is required to be able to meet the 20 percent by -- whoops, that should say by 2010 renewables goal.

They also think that they need new transmission -- if they can't get local generation to meet local reliability requirements. And the concern there is whether there is sufficient air pollutant offsets to provide inbasin generation that would be alternative to transmission.

We didn't feel we had enough information in either filing, either the supply filing or the transmission filing, to verify either of these

claims. But we didn't think they were all that
outlandish.
That's the end of my presentation. Have
any other questions from the survivors?
PRESIDING MEMBER GEESMAN: Scott.
MR. CAUCHOIS: Scott Cauchois, ORA. I
thought, just referring to a couple of things that
have come up. On the question of Mojave we
recommended that it be looked at as a, you know,
in-and-out type of scenario. And ORA would hope
that if Edison proceeds with Mojave that it would
do so on the basis that it's economic.
And I think the reason that we
recommended that it be just considered in this way
is that it is an open proceeding at the PUC. And
somewhat of a wild card. And as everybody knows,
has issues of water, jobs for Indian tribes, jobs
for coal miners. And there are proposals by
renewable folks to put something out there. So it
may just -- there's always that risk that it could
take on a life of its own and not proceed the way
it's ideal to us.
And then I have a --
PRESIDING MEMBER GEESMAN: When you say
economic, Scott, do you mean subjected to the same

type of review in the procurement process?

MR. CAUCHOIS: Yes.

PRESIDING MEMBER GEESMAN: Okay.

MR. CAUCHOIS: And then on the departing load, yeah, I sympathize with Edison. I mean it's true that you can look at departing load from a probablistic standpoint, or speculate there could be a core/noncore market. And the PUC has been promising that we'll make all you IOUs whole.

But what's a complete unknown is the conditions going the other way, which is the conditions under which they might come back.

PRESIDING MEMBER GEESMAN: The re-entry rights.

MR. CAUCHOIS: The re-entry rights, or in our preference, the non re-entry rights.

PRESIDING MEMBER GEESMAN: Um-hum.

MR. CAUCHOIS: In other words, there have been proposals to completely segregate the markets the way gas is, which again changes the risk profile for the utility completely.

Or on the other hand if there are entities in the country that have fairly smooth re-entry rights, but in those cases they have a strong, you know, ISO-type of backstop market to make sure that costs aren't imposed on bundled ratepayers.

So, it's that other type of switching that ought to be of concern including even existing direct access. I mean there's nothing that makes existing direct access some sort of a permanent feature. The utilities are, essentially today, the providers of last resort for that load. So, --

MR. HEMPHILL: If I could add something. This is an industry that's dominated by the retail structure. And what happens in the retail structure defines how the wholesale structure will unfold, and how generation will be financed, and everything else. And that's why it's absolutely critical that we get our arms around what the future retail structure will be for the industry.

MR. CAUCHOIS: And you may have your arms around it after the November election, I mean, you don't know.

MR. HEMPHILL: I think there'll still be some implementation details beyond that.

PRESIDING MEMBER GEESMAN: You mean teacher tenure is going to impact this?

(Laughter.)

PRESIDING MEMBER GEESMAN: Or reapportionment?

But, Scott, you're more concerned about the return uncertainty than the departure uncertainty?

MR. CAUCHOIS: Well, I mean if I were a utility trying to plan resources, I mean I suppose I'd be much less risk averse than say Edison is today, from the point of view of who could depart, in the sense that if I signed a contract and some load left, the PUC has said, okay, we'll make you whole, or we'll charge exit fees.

But the current structure still has Edison as the provider of last resort. So can Edison, you know, just or a utility just say, well, now I can just ignore those customers forever. No, they can't do that. And those rights of return haven't been spelled out. You know, I mean that core/noncore structure is sort of, you know, stalemated for right now anyhow.

But, if you were to -- I mean, I agree, if you were to adequately do a scenario around this then you might as well specify the different sets of rules that might apply, such as are you going to completely segregate the core and the noncore markets in which they both carry their own obligations and that's it.

Or are they not completely separated; the noncore has some right to return to core. And which, you know, which creates a different set of questions for the utility.

So I'm just saying there are a lot of assumptions about what type of a core/noncore structure you have that dictate what the risk profile is for the utility.

MR. HEMPHILL: To add a little flavor there, during the crisis we had a period where 10 billion kilowatt hours became our obligation. And then it disappeared over a matter of a couple of months. That's a lot of procurement. And if you don't know how much to plan for, you'll either over-procure, which is less of a problem, or under-procure, which can be a substantial problem.

And so in that case I definitely agree with Scott.

MR. LaFLASH: I wanted to expand on Scott's in the same extent that Stu did, is that if you have stranded costs it's a financial issue. If you don't have enough resources the lights go out.

We think resource adequacy is a key issue that if someone else is going to be providing that load they need to have adequate resources behind them, need to meet a certain counting standard.

I probably should respond to what Commissioner Geesman brought this up earlier, but I got tired of jumping up and down so I thought I'd take a seat, too. We do believe in the protections of the stranded cost and exit fee provisions of the PUC's December decision. But we're still trying to be responsible about it and make certain that we're not over-procuring. We're trying to keep those stranded costs down.

But we do have the concerns that Scott has, is that if they come back and we didn't expect them to come back because they didn't provide their own adequate resources, then we have a reliability problem.

PRESIDING MEMBER GEESMAN: And, Stuart, do you share what I think both of the two prior comments suggested, that the return right is a much larger problem than the departure right, giving some credence to the PUC's pronouncements on exit fees?

MR. HEMPHILL: Yeah, when I look at the cost of blackouts to California, it's immense. Yes, there are stranded costs and elements of over-procuring indirect access, but I have a greater concern that customers needs won't be met. So I agree with my PG&E counterpart.

PRESIDING MEMBER GEESMAN: Okay.

MR. KELLY: Could I weigh in for just a second on this because while I agree with the comments that resource adequacy is theoretically a tool to help mitigate the lights going out and all those problems, I don't necessarily agree that -- I mean the provider of last resort in California today is essentially the ISO.

The return DA customers, in my view, are really no different than what occurs when there's under-scheduling. You get load showing up in a real time that the ISO's serving under RMR contracts, or whatever contractual rights it has to run units. And that obligation has essentially shifted off the utilities' back in real time into the ISO, if they under-schedule, which is almost equivalent, from an engineering perspective, as if DA load shows up in real time that they hadn't contemplated for.

I don't see they're really that different.

MR. HEMPHILL: Mr. Kelly, I would encourage you to talk to the Cal-ISO. Over the last two weeks they've determined that it is the ESPs that under-schedule and not the utilities.

MR. KELLY: Any ESP that under-schedules. But the return of DA, for example, in real time, which was a problem that was raised, is really very similar. It's just energy demand showing up in real time. And the ISO is the one that ends up stepping up and serving it through its RMR contracts.

MR. LaFLASH: Steve, I'll bet you the headline doesn't read: ISO customers blacked out.

MR. KELLY: I'm just telling you mechanically what occurs. So it doesn't do any good to mischaracterize it here when we're amongst ourselves talking about what's really going on in California.

I mean if it's going to be used as an argument for why DA is good or bad, we should at least characterize it properly.

MR. CAUCHOIS: Well, I mean I think you're only partially right. When I see the ISO have the ability to either, you know, black those customers out of the entity that was short, or assess the full cost of that shortage to those customers, then I'll say the ISO has the problem.

MR. KELLY: Well, I --

MR. CAUCHOIS: But not just the ability to assess RMR costs to everybody in whatever region it is that pays the RMR costs.

MR. KELLY: Well, right. Now, though, effectively what happens is the ISO will, under its tariff rights, run as much generation as is available to meet the load. Now, if there isn't enough generation in the region to meet the load, then you're going to have the blackouts. But the ISO will run what it can up to its price controls.

So it turns out to be a mechanism to lean on the -- you know, it allows load to be served up to the price caps.

MR. HEMPHILL: That assumes that the resource adequacy is not being met. Is that your assumption? I mean the whole point of --

MR. KELLY: Well, in real time, yeah.

MR. HEMPHILL: Well, in real time --

MR. KELLY: I mean resource adequacy is a forward obligation.

MR. HEMPHILL: It is a forward obligation, and, you know, you are to have 90 percent of your expected peak demand, 115 percent of 90 -- however that works, 90 percent of 115 percent. But a month ahead it should also be available.

So what you're talking about is a failure of resource adequacy to actually be implemented appropriately.

MR. KELLY: Well, as I pointed out, I think when resource adequacy is actually implemented, hopefully for next summer, I think these problems are marginal.

MR. LaFLASH: Well, there's still the longer term issue because the resource adequacy requirement so far is one year. One year doesn't get a new resource built.

PRESIDING MEMBER GEESMAN: Yeah, I think that the easiest way to look at it in terms of this Commission's concerns, is the longer term time dimension. We have not engaged in any level of detail in market structure debate, and specifically not in the real time market structure debate.

We do make some policy judgments known,

as we did in our '03 report, where we suggested that a core/noncore structure needed to be examined. And we subsequently provided conceptual support to Commissioner Peevey's particular proposal for a core/noncore structure.

But our concerns are more in the longer term dimensions of market structure. And I've heard each of you, with the exception of you, Steven, indicate that the prospect of returning direct access customers looms larger as an uncertainty or risk than the prospect of departing customers. That assumes a certain effectiveness of the PUC's pronouncements on exit fees and the avoidance of cost shifting.

But if I'm wrong in wanting to focus on those return rights from a policy standpoint, I hope you guys disabuse me of that. If not today, then in your written comments.

MR. CAUCHOIS: Well, I think that this idea of the obligation beyond that year that is the resource adequacy obligation that we're going to have in California in the short term. But whether that obligation should be longer term is a topic of discussion all over the country right now, in fact, different parts of the world, in people designing capacity markets or redesigning capacity markets.

And so I think you're right to have the longer term perspective. And once you get out beyond that one year, the perspective really is that we're not quite sure what the length of that obligation should be on either side, either on the customers that go out to noncore -- I mean they have a term obligation that some people have proposed that could be, even if it's not permanent, that it's some years. Or if they return, that it's some years.

But none of these things have been pinned down. And they all affect how you look at the longer term.

MR. KELLY: I think the --

MR. HEMPHILL: Depending on how the call them coming-and-going rules are defined, that will also define whether new investment is made in generation. Because that allows for longer term commitment. The stability of retail customers allows for longer term commitments. You don't even necessarily need a longer resource adequacy requirement if the rules are appropriately made on the retail. That's why I indicated earlier that is the defining element for this industry in California.

PRESIDING MEMBER GEESMAN: And, Scott, if I understood your earlier comment correctly, ORA believes the preferable approach would be once you're gone, you're gone.

MR. CAUCHOIS: Yes, that's -- we've indicated that if -- I mean that would be our preference out of all the different choices for that type of structure.

But, I can say that, you know, we'd be open -- I mean I do understand there are some jurisdictions with a different type of, I guess I'll call it a ISO-back-stopping structure or a capacity market where you could have mobility that leaves people indifferent on both sides.

But, again, under that you'd have to -- that process, as I understand it, would be pretty well designed to remove the risk for the load-serving entities in long-term commitment.

At the same time, though, none of those entities are totally sure that whatever structure they have is actually inducing long-term investment. I mean that's a big research question out there.

MR. KELLY: Yeah, but your report, I presume, is going to look at the long term assuming a resource adequacy requirement of 115 percent. I mean when you stack your stuff --

PRESIDING MEMBER GEESMAN: Yeah, but with a heavy expressed concern to the necessity of meeting the state's infrastructure requirements.

MR. KELLY: Right, and that's fine. But I mean your picture that you paint is going to be a picture that would be painted for all the LSEs about this is what we see, this is the resource additions, if any, that you're going to need in order to meet that based on our projection of what know today, blah, blah, blah.

So people are going to have a long-term view of what it's going to take to be roughly resource adequate under the vision that you're going to articulate here. So that should be an important signal for the load-serving entities, all of them, to engage to meet that need.

And if we do have a tradeable capacity market, which allows for the mobility of the capacity value that people are buying into at the front end, I think that will go a long way to help relieve some of the concerns, as well.

PRESIDING MEMBER GEESMAN: My hunch is that by the time our report is issued in November we won't have a tradeable capacity market.

MR. KELLY: We probably won't even have a phase two decision.

(Laughter.)

MR. HEMPHILL: I think that's a good hunch.

MR. KELLY: But it will still be a vision that will tell people, you know, out on a horizon that we think there's a need for capacity. It's going to send a signal to the PUC to, you know, your estimated extent of that need. And presumably there'll be action taken on that now so that we're not caught short.

PRESIDING MEMBER GEESMAN: Yeah, but I guess if the current standoff over this question of the utilities having inadequate certainty about who their customers in the future will be, that current standoff is inhibiting investment -- and I would submit that it is -- or if it is skewing procurement in such as way as to inhibit investment. And I mean by investment, long-term capital investment that builds new infrastructure.

Then I think that our report is going to need to identify that problem. And within the limits of our ability, make some recommendations as to how to address it.

MR. KELLY: Yeah, I expect you will. If there's a problem then we'd want to solve that. I mean we're interested in making sure that there's a reliable system.

PRESIDING MEMBER GEESMAN: Have either Edison or PG&E expressed a view as to a preference on return rules? I mean Scott indicated ORA has a pretty clear preference in the ideal world, that once you're gone you can't come back.

Do either of your companies share that view? Or have you looked at more of a range of alternatives?

MR. HEMPHILL: I think we've looked at a range. I know at times we've expressed exactly the same point of view. I know, also, that particular view is not palatable for a lot of our customers. And so we do find, try to find the right balance of coming and going rules. I think that's what you would find if you looked at our PUC dockets -- excuse me, PUC filings on the subject.

MR. LaFLASH: I don't think we've ever

gone as far as what Scott recommended for the same reasons Stu said, that's not what our customers want.

But we do believe there's a need for reasonable switching rules and long-term resource adequacy rules so we can get the infrastructure built.

PRESIDING MEMBER GEESMAN: Rob, can I pin you down? Green light.

MR. ANDERSON: You can't pin me down, but I know this very topic is being discussed actively right now in a CCA proceeding, a phase two CCA proceeding at the Commission.

I know we have laid out some, I'll say some rules there, or at least some structure for putting rules in. I just can't recall exactly what SDG&E's proposal was at this time.

PRESIDING MEMBER GEESMAN: And would you envision the same rules applying to direct access customers as applying to community choice aggregators?

MR. ANDERSON: Off the top of my head I see it's a very similar issue. It's the utility trying to understand what load it's going to serve, and for what time period.

MR. LaFLASH: The only difference that I can think of is in these exit fees and surcharges that you mentioned earlier, they apply to customers that are now served by the utility. They don't apply to current direct access customers.

So if those direct access customers came back they may need to be treated differently. We haven't formed an opinion on that.

PRESIDING MEMBER GEESMAN: Okay. Other topics that we ought to address? The President's speech last night? Basketball game?

(Laughter.)

MR. MILLER: I just have 12 more slides to go through.

HEARING OFFICER FAY: Okay, Ross, --

(Laughter.)

MR. MILLER: No, actually, I just wanted to take the opportunity to thank staff for this report. It was kind of an unusual interdivisional project, and I think it was very fruitful.

And I also wanted to thank the utilities for all the work they put into the filings. As Edison said, it was mountains and gigabytes of material. And it was, I thought, thoughtfully put together. And where it wasn't everything we wanted it to be, I think there were pretty good challenges described why they couldn't do that.

PRESIDING MEMBER GEESMAN: Let me make certain that -- oh, we do have a comment from the audience. Please come up and --

MS. FREEDMAN: Right, I --

PRESIDING MEMBER GEESMAN: You need to identify yourself.

MS. FREEDMAN: This is my first time doing this, so, I'm sorry. I did submit a blue card, but I don't think it made it your way.

PRESIDING MEMBER GEESMAN: It's my mistake. You must be Susan Freedman.

MS. FREEDMAN: That I am.

PRESIDING MEMBER GEESMAN: San Diego Association of Governments Energy Working Group.

MS. FREEDMAN: Two places. I'm actually the Senior Policy Analyst for the San Diego Regional Energy Office, and I also serve in a staff role to the San Diego Association of Governments in their Energy Working Group. So I'm here today in that role.

And I wanted to just provide a little bit of insight on what the Energy Working Group is planning to do in conjunction with SDG&E for the 2006 plan.

I appreciate the opportunity to come and provide comment today. And it's on the role of the EWG and providing direction and input in the 2006 submittal with SDG&E.

The Energy Working Group, for those who aren't aware, represents 18 cities and the County of San Diego, as well as large business, small business, labor and environmental groups. SDG&E, as well as San Diego Regional Energy Office also are members of the working group.

The number one priority that the working group identified for this year is to work in conjunction with SDG&E in the development of its 2006 resource plan. And a big reason that this is important is because other than keeping the lights on and following the requirements of the CPUC and the CEC, we want to make sure that SDG&E takes advantage of the policy goals and drivers that were brought forth in the regional energy strategy for San Diego.

Within the regional energy strategy, very briefly, it promotes renewable energy, energy efficiency, distributed generation. It also shows a preference for inbasin power generation over importing and having reliance on outside generation.

Several San Diego stakeholders, during the 2004 long-term resource plan process, had submitted comments to the CPUC regarding concerns they had with the 2004 submittal. And SDG&E was very forthcoming and helpful in explaining why they acted differently than what the commenters had said.

But in the end none of the comments brought forth by the community and stakeholders were brought forward into the final plan that SDG&E submitted. So it seemed it was a little too late in the process.

So that's what the Energy Working Group, with SANDAG, has wanted to move forward with getting in at the front end, and getting -- creating an open venue for discussion and direction of policy drivers locally to have it incorporated into the 2006 submittal.

So with that, Rob Anderson, I would like to state, and SDG&E, has been very helpful in educating us on the 2004 plan. And helping provide somewhat of the lay of the land on what's going to happen going forward.

And I just wanted to alert everyone today to the fact that the Energy Working Group is looking forward to working with you all and the PUC and continuing the SDG&E in this process.

Just as a final note, Alan Sweedler, with SDSU, who is also a member of the Energy Working Group, he'll be here tomorrow to further elaborate on the EWG's goals and roles in this matter.

So thank you very much for your time.

PRESIDING MEMBER GEESMAN: Well, thank you. I wonder if you would elaborate a bit on the reasons for your preference for inbasin resources as opposed to imports.

MS. FREEDMAN: Part of that had to do with during the electricity crisis, when it first hit the San Diego area, over all the rest of California, and we were paying exorbitant prices before anybody else.

And we just have a very high reliance, which is a fear factor, locally among residents and businesses. So it started from there when the regional energy strategy was being developed in 2002 and 2003, that we no longer wanted to have to heavily rely on importing power.

So, in looking in that, too, I think the region and comments that have come up in the past was well, what about repowering facilities there, a bigger reliance on renewable energy in-region. And just being more self reliant. I think that's a security issue and concern, as well.

PRESIDING MEMBER GEESMAN: I want to stay engaged on this question as we go through the remainder of this cycle this time, and in the future, as well.

And I would express a cautionary note, because I've met with a variety of your members, that that can also be a thinly disguised rationale for opposing new transmission projects. And I think one of the problems that has beset your part of the state has come from the fact that it is so poorly interconnected with the rest of California and the rest of the west. I think your rates would be significantly lower had the state made a higher priority of improving the interconnectedness of San Diego with the rest of the west.

And I'm hopeful that one of the things that emerges from our report is a renewed emphasis on the desirability of doing that. I think we've heard now in several of our workshops the importance of better interconnectedness to reaching out-of-basin renewable resources. But I think there are other reasons, as well.

And I think ultimately your region is likely to be better served, and certainly enjoy the benefit of lower rates if you are less of an island in our transmission system than you currently are.

MS. FREEDMAN: I agree with those comments, and in looking at Valley-Rainbow, that would have been a great benefit. And I don't think the Energy Working Group would be against transmission. I think where concerns come up is just looking at the timing and making sure that it doesn't create a barrier to more in-region renewables and whatnot.

PRESIDING MEMBER GEESMAN: And I think that's a worthy objective, as well.

MS. FREEDMAN: So I don't think anyone's against transmission --

PRESIDING MEMBER GEESMAN: Well, I know there are some that are. And I intend to continue to push back pretty hard on that.

MS. FREEDMAN: But with the working group. Thank you very much.

PRESIDING MEMBER GEESMAN: Thank you. Are there other members of the audience that would like to address us? Anybody on the phone?

MR. PIGGOTT: Yes, this is Jack Piggott; I'm still here. I just had a general comment, and I understand that you've been highly constrained by confidentiality issues on this report.

But given that it's going to be the basis for, or that it's perhaps going to lead to another report that will be the basis of PUC procurement, and that the specifics are lacking due to confidentiality, we really don't -- other market participants and members of the public really don't have any way to challenge the assumptions and see if they're valid. One point, you know, make our argument.

And additionally, the results of the report doesn't really form a basis for developers, generators to site new facilities. If we don't really know what type of power is needed, and where and when, it's difficult -- it's just not helpful in siting new generation.

And I guess I question why the

confidentiality is such an issue, given that this report doesn't even start till 2009. Certainly, you know, any way that other market participants would be able to use this would mostly be to site new generation.

PRESIDING MEMBER GEESMAN: Well, --

MR. PIGGOTT: I guess I would hope that later on, or that the next version of this could be more specific, and could indicate, you know, a breakdown of what types of generation, you know. How much renewable, how much baseload, how much peaking. Ideally where would it be located. And when would it be procured.

MR. HEMPHILL: I'd be happy to address that. I think all of those questions can be answered without indicating what utilities' residual net short position is. What we've found is that generators are quite adept at taking bits and pieces of information and using it to increase prices. And that's the big concern over confidentiality.

The only thing, from our perspective, that generators need to know to bid into a solicitation that does define what and where is needed -- and where it's needed, is the generator's cost. And anything additional will be used to increase prices. We've seen that time and time again. In fact, the woman who came in and spoke about her organization developing was talking about the price increases that took place during the crisis. And that is a great example of information being too available to market participants.

I have one other thing to address, which is you indicated that information isn't available. And I disagree with that. We readily make it available to anyone who is willing to sign a nondisclosure agreement.

PRESIDING MEMBER GEESMAN: I doubt that you'd make it available to Mr. Piggott who represents Calpine. I think you've confined that in the past to nonmarket participants.

MR. HEMPHILL: I believe the rest of my comments are still valid.

(Laughter.)

MR. KELLY: I would actually take Edison up if they can -- sounds like Stuart said that they are able to, or at least interested in developing a plan that would tell market participants the what, where and when without revealing the net short, which is great.

MR. HEMPHILL: I believe that the CEC is in a great position to talk about regional generation needs, the load, the aggregate loads and resources. And that's something I can't do. I don't know other load-serving entities' loads and resources.

When generation is sited it has to be, I mean it's most helpful in a transmission-constrained area. And the CEC is in great position to talk about the need for that kind of generation. It's not something I can do, and it's not to meet my bundled customer needs.

MR. PIGGOTT: Would it make sense then that to not use this for procurement, but let the CEC then go out and use it, its own information, to generate a resource plan and use that, have the PUC use that for procurement?

PRESIDING MEMBER GEESMAN: Well, I don't want to answer any of these questions today, Jack. I'd prefer to let the report that we submit speak for itself.

I would also encourage you and the other participants here today to make these arguments on confidentiality at the Commission's July 13th business meeting. We will be hearing the appeals of each of the three investor-owned utilities from our Executive Director's ruling on the confidentiality of the supply-related information.

We previously upheld the Executive Director as it related to demand side information. And are being sued by one of the IOUs because of that decision.

We'll have these issues on the supply side in front of us on the 13th, and make the best decision we can thereafter.

MR. LaFLASH: I'd like to say one thing. Jack, this is Hal LaFlash of PG&E -- a comment on your comment and on Steven Kelly's comment.

We just held an RFO and just told the market the what, where and when. We said we needed 1200 megawatts of peaking and shaping resources, and another 1000 megawatts two years later of intermediate resources.

When we have a need we describe that need, describe the products we need, and go forward with an RFO.

MR. PIGGOTT: I appreciate that, and, you know, I guess my comment has to do with the fact that this is a long-term procurement report, or I guess needs report. And, you know, we're looking at the timeframe of 2009 to 2016.

To me, I think having information or projections about that, which I guess Commissioner Geesman had indicated is with a broad paintbrush, that, you know, how we're making these projections. That having that information out there doesn't give anyone the opportunity to manipulate prices. Instead it just gives everybody a common basis on which to plan.

And, you know, I appreciate that in your RFOs you have given us information. And I guess my only point is that if we had more information going out further in the future, that we'd have sites permitted and be able to respond to those RFOs, you know, with better projects.

MR. LaFLASH: This is Hal LaFlash again.

I think there were some takeaways in this report today that disclosed more of what we need in the future.

I think all three utilities say we need more peaking and shaping resources. And not as much baseload.

And I think that's going to be the case as long as we keep trying to add as many renewables as possible, because renewables generally don't have those features. And we need those features to complement the renewables.

MR. HEMPHILL: For Edison that's the case through the end of the decade. You know, we're long most hours, and that's primarily due to DWR contracts and other baseload resources that we have.

So we've said that; we need peaking; we need shaping resources. That's what we need.

MR. PIGGOTT: I understand that, as well. I guess my complaint is in these tables where there are numbers that, you know, there's a net short number, and then there's another number from bilateral contract and other resources and new resources, and they're all lumped together, renewables and everything else.

MR. HEMPHILL: I would recommend the report that was released today. I think it's more complete and you'll find more detail in that to your satisfaction.

MR. PIGGOTT: Okay, great.

PRESIDING MEMBER GEESMAN: Any other comments?

Okay, thank you, all, for a very

productive afternoon.

We'll be adjourned.

(Whereupon, at 4:15 p.m., the hearing
was adjourned.)

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CERTIFICATE OF REPORTER

I, CHRISTOPHER LOVERRO, an Electronic Reporter, do hereby certify that I am a disinterested person herein; that I recorded the foregoing California Energy Commission Hearing; that it was thereafter transcribed into typewriting.

I further certify that I am not of counsel or attorney for any of the parties to said hearing, nor in any way interested in outcome of said hearing.

IN WITNESS WHEREOF, I have hereunto set my hand this 11th day of July, 2005.